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CONGRESS OF THE UNITED STATES
Office of Technology Assessment
Washington, D. C. 20510

Oil and Gas Technologies for the Arctic and Deepwater

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Foreword

Nearly 2 billion acres of offshore public domain is owned by the United States adjacent to Alaska and the lower 48 States. Much of the Nation's future domestic petroleum supply is expected to come from this area. Areas of highest potential apparently occur in deeper water and in the Arctic where operating conditions are severe, development costs high, and financial risks immense. As the pace of exploration increases in these “frontier” regions, questions arise about the technologies needed to safely and efficiently explore and develop oil and gas in harsh environments.

The Office of Technology Assessment undertook this assessment at the joint request of the House Committees on Interior and Insular Affairs and on Merchant Marine and Fisheries. The study explores the range of technologies required for exploration and development of offshore energy resources and assesses associated economic factors and financial risks. It also evaluates the environmental factors related to energy activities in frontier regions and considers important government regulatory and service programs.

In March 1985, the Secretary of the Interior announced the Administration's proposed new 5-year offshore leasing program that will determine the pace of oil and gas exploration in Federal offshore waters through 1991. The proposed leasing schedule will be under review by the 99th Congress, with final approval slated for the Summer of 1986. OTA's report on Arctic and deepwater oil and gas is intended to provide a timely and useful reference for the Congress as it reflects on the Department of the Interior's proposed program.

OTA is grateful to the Offshore Technologies Advisory Panel and participants in OTA's workshops for their help in the assessment. Splendid cooperation was received from a number of executive agencies during the course of the study, including the Minerals Management Service, National Oceanic and Atmospheric Administration, and the U.S. Coast Guard. Special thanks go to the Arctic Environmental Information and Data Center of the University of Alaska and its Director, David Hickok, for field assistance to OTA in Alaska.

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Chapter 1

Summary, Issues, and Options

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Chapter 1

Summary, Issues, and Options

INTRODUCTION

This assessment addresses the technologies, the economics, and the operational and environmental factors affecting the exploration and development of energy resources in the deepwater and Arctic regions of the U.S. Outer Continental Shelf (OCS) and the 200-mile Exclusive Economic Zone (EEZ) established in March 1983. For the purposes of this study, OTA defined "deepwater" as those offshore areas where water depths exceed 400 meters or 1,320 feet. The "Arctic" is defined as the Beaufort, Chukchi, and Bering Seas north of the Aleutian Islands.

Leasing submerged coastal lands for oil and gas development began with State programs in California, Louisiana, and Texas years before there was a Federal offshore leasing program. Leasing in Federal offshore lands began in 1954 after the Outer Continental Shelf Lands Act of 1953 provided the Secretary of the Interior guidance and authority for such activity. The industry leased, explored, and developed OCS oil and gas under the provisions of the 1953 Act for 25 years. Most of the offshore activity during that period was in the Gulf of Mexico and the Pacific Ocean off southern California. Then, in 1978, an emerging national awareness of the environment coupled with the Arab oil embargo and increased concern about energy supplies led to enactment of the OCS Lands Act Amendments.

Congress included in the 1978 amendments a directive that the Secretary of the Interior seek a balance in the OCS leasing program that would accommodate "expeditious" development while protecting the environment and the interests of the coastal States. The amendments established procedures for considering environmental and State concerns in leasing decisions, required the orderly formulation of future leasing schedules, and ordered experimentation with a variety of alternative bidding systems. In seeking to balance energy development and other values, the offshore leasing program has been the target of criticism from coastal States, environmentalists, and the industry. These criticisms have sharpened in the 1980s as offshore activities have expanded into the deepwater and Arctic frontier areas.

The revised leasing system mandated by the 1978 amendments has been in place slightly more than 6 years. During this period, two Presidents and four Secretaries at the Department of the Interior left their mark on the implementation of the offshore leasing program. In addition, Secretary James Watt initiated a major departmental reorganization which brought together components of the Bureau of Land Management, the U.S. Geological Survey, and the OCS policy office in the Office of the Assistant Secretary for Policy, Budget, and Administration. These were placed in a newly formed Minerals Management Service (MMS). Responsibility for Secretarial oversight of MMS was shifted from what was once the Assistant Secretary for Energy and Minerals to a new secretarial directorate in the Office of the Assistant Secretary for Land and Minerals Management.

The changes in leadership and the reorganizations, the shift in leasing from nearshore areas to offshore frontier regions, and the short period of time since the passage of the 1978 amendments have all affected the offshore oil and gas leasing program. In spite of the fact that it has proven to be one of the government's most controversial natural resource programs, the offshore leasing program has generally performed well in achieving the objectives set by Congress. It is unlikely that any statutory framework devised to expand and expedite exploration for oil and gas on Federal lands, while giving equal weight to protecting the environment and honoring the sovereign goals of the States, can be anything but adversarial and contentious. Despite the conflicts which have arisen, leasing of offshore oil and gas has worked more smoothly and efficiently than other Federal energy leasing programs.

The existing OCS Lands Act appears to provide Congress and the executive branch sufficient latitude to guide the leasing program in any direction that public policy may dictate. In general, the OCS Lands Act allows the administrative flexibility needed to adjust leasing terms and conditions to deepwater and Arctic frontier areas.

OFFSHORE RESOURCES AND FUTURE ENERGY NEEDS

Energy supply and demand projections to the end of the century indicate that demand for oil and gas in the United States will increase and domestic supplies will not. Falling oil and gas prices have reduced incentives to conserve energy and to substitute alternative fuels for petroleum products. At the same time, domestic oil production is likely to decline and the country is unable to maintain its reserves. Oil imports, which have declined in recent years, are expected to gradually increase and may again reach the high levels of the 1970s.

Forecasts by the Department of Energy and the Gas Research Institute indicate domestic energy shortfalls may necessitate oil imports over 7 million barrels per day and natural gas imports of about 3 trillion cubic feet per day by the end of the century. Projections by OTA and the Congressional Research Service anticipate higher oil import rates in the 1990s, perhaps again reaching the historic 1977 high of 9.3 million barrels per day. Predictions of declining real oil prices in the short term, which would reduce incentives for exploration and production of domestic resources, make even these forecasts optimistic. Oil imports of the magnitude expected in the 1990s would make the country more vulnerable to supply interruptions and would increase the trade deficit.

Where might new domestic oil and gas resources be found to assist in meeting future U.S. energy needs? The onshore areas of the lower 48 States are the most densely explored and developed oil provinces in the world. But—with the exception of Prudhoe Bay, the largest field in North America—few sizable onshore discoveries have come on line during the past decade. Domestic reserves continue to dwindle. It is unlikely—but not impossible—that a giant field similar to Prudhoe Bay will be found onshore in the lower 48 States.

Most of the undiscovered oil and gas in the United States is expected to be in offshore areas or onshore Alaska. But resource estimates of undiscovered oil and gas, while useful as indicators of relative potential, are little more than educated guesses. Experts agree that prospects for oil and gas offshore are good, but they also admit there is a chance that only an insignificant amount of economically recoverable oil and gas may be found. In fact, only one major offshore field of a size needed to significantly increase reserves—the Point Arguello Field off southern California—has been discovered since offshore exploration was accelerated in the 1970s.

Exploration in the offshore frontier regions during the last 5 years has yielded some information—most of it negative—about potential oil and gas resources. The U.S. Geological Survey estimated that between 26 and 41 percent of the future oil and between 25 and 30 percent of the future natural gas is offshore. The most promising prospects are believed to be in the deepwater and Arctic frontiers. However, MMS recently lowered the estimates of undiscovered recoverable offshore oil by half and of natural gas by 44 percent as a result of unsuccessful exploration efforts in Alaska and the Atlantic.

Much of the 1.9 billion acres within the offshore jurisdiction of the United States is still unexplored. Only actual exploratory drilling can determine the presence of hydrocarbons. The offshore oil and gas industry will drill the most promising geological structures as exploration expands in the Arctic and deepwater frontiers. If significant reserves are not discovered in the first round of drilling, the government may need to consider a "second-round" leasing strategy to induce the industry to drill second-level prospective structures.

If Congress wishes to pursue the objectives of the OCS Lands Act, it is important that the oil and gas industry have access to Federal offshore lands to more accurately determine the resource potential of frontier areas. A "second-round" leasing strategy may also be needed to assess the extent of smaller offshore reservoirs that could cumulatively contribute to the Nation's energy security.

TECHNOLOGIES FOR ARCTIC AND DEEPWATER AREAS

Developing oil and gas in the deepwater and Arctic frontiers will be a major technological challenge. The severe environments and remote locations will require the design and construction of innovative and costly exploration and production systems. **The key to safe, efficient, and economical development of offshore resources in these frontiers will be the technology used for exploring, producing, and transporting oil and gas under some extreme environmental conditions.**

Offshore technology has generally developed—and will probably continue to develop—in an evolutionary fashion. Once wholly landbased, the oil and gas industry has moved its onshore technology offshore, first onto piers, then onto seabed-bound platforms, and finally onto floating vessels as it ventured into deeper water.

Exploration systems have been operating in many deepwater and Arctic areas for several years. But production systems have not yet been installed in frontier areas. Several production systems have been designed, however, and some have been tested in prototype. In addition, many of the individual components that make up total production systems are in service elsewhere in the world. The systems finally adapted for use in the deepwater and Arctic frontiers probably will be a combination of previously tested subsystems and new components designed to withstand specific and often severe conditions.

The industry may be characterized as cautiously conservative in its approach to designing and deploying new technology. **Yet, in general, it appears that development of offshore technology is progressing at a pace compatible with government leasing schedules and projected exploration and development timeframes.**

Arctic Technologies

The severity of the Arctic environment generally dictates a rigorous approach to design and construction of all primary and support systems. The cold temperatures, ice, harsh weather, and remoteness of many Arctic regions will force the use of costly equipment to achieve required reliability.

Technology for meeting the challenges of the Arctic will have to develop concurrently with exploration for oil and gas. Because of the immense costs of development in this hostile environment, there is a tremendous incentive for industry to design and build using advanced technologies and materials that will ensure reliability and cost effectiveness. This is particularly true for production systems which, unlike exploration equipment, must withstand the severe, exposed, and corrosive conditions for the life of the field—usually 20 years or more.

In order to assess the technology needed to explore, develop, and produce oil and gas in the Arctic, OTA studied hypothetical sites at Harrison Bay in the Beaufort Sea, the Norton Basin in the Bering Sea, and the Navarin Basin in the Bering Sea. Each of the three Arctic scenarios was based on different assumptions of environmental conditions, water depths, oil field sizes, and production rates, which consequently call for different technologies.

Study of the OTA scenarios and review of available industry and government Arctic research and development programs indicate that priority should be given to additional research related to ice properties, ice movements and forces, oceanographic and meteorological processes, and seismicity.

Sea ice is considered to be the most important design factor for engineering in the Beaufort, Chukchi, and northern reaches of the Bering Seas. Additional research is needed to obtain basic data on ice strength, ice forces due to movements, and ice properties under the range of conditions likely to be encountered. Better surveillance of ice movements from satellites and aircraft could provide more accurate and up-to-date information. Additional research and development may be warranted on more rapid and effective trenching techniques to bury subsea pipelines below ice-gouge depths. The construction of ice-breaking tankers that are capable of working year round in the Beaufort and Chukchi Seas will require better design data. For the St. George and North Aleutian Basins, more information is needed on seismic activities associated with the subduction of the Pacific plate beneath the North American plate.

Deepwater Technologies

Deepwater technologies must be developed to withstand such environmental factors as water currents, seafloor instability, mud slides, and hurricane-force winds and waves. In the United States OCS, there has been a natural progression of offshore technology from shallow water into ever-increasing depths. As the severity of the operating environment has increased, incremental modifications have been made to basic designs to deal with these changing factors. In general, as depths have increased, structures have become larger, more substantial, and consequently, more expensive. To assist in understanding the technology needed to explore, develop, and produce oil in the deepwater frontiers, OTA studied a hypothetical site off the central California coast in water depths of up to 4,100 feet.

Exploratory drilling in very deep water is limited by extreme ocean waves and currents and subsea formation conditions which make drilling slow and difficult. To date, the deepest offshore exploration well was drilled in 6,952 feet of water in the Atlantic offshore region in 1984. The Department of the Interior is now offering leases in 7,500 feet in the Atlantic and up to 10,000 feet in the Pacific.

The deepest water from which oil is currently being produced is 1,025 feet in the Gulf of Mexico. Discoveries have been made in 1,640 feet of water in the Gulf of Mexico, but production systems are only now being developed. In the Mediterranean Sea, development wells have been drilled in 2,500 feet of water, but production has not yet begun.

Nearly all offshore fields discovered thus far have been developed using fixed-leg production platforms. This trend has been an extension of scaled-up shallow-water technology. Technically, fixed-leg platforms can probably be designed for water depths of 1,575 feet or more. However, the immense amounts of steel required, coupled with the cost of fabrication and installation, may limit the economic application of fixed-leg platforms to water depths of about 1,480 feet

It is reasonable to expect that in a few years, several types of production systems will be designed and built for water depths of 1,640 to 2,500 feet. Advanced conceptual design and some component testing are underway for compliant and floating platforms, subsea wellheads, and submerged production systems for these water depths. However, there has been limited effort to develop site-specific engineered solutions for use in deeper waters because of the lack of commercial discoveries.

Industry experts generally agree that current technology may be extended to about 8,000 feet without the need for major breakthroughs. Existing technologies which are particularly promising for deepwater include buoyant towers, tension leg platforms, and subsea production units. All but the subsea production units are generically referred to as "compliant structures," which flex and give way under wind, wave, and current forces.

A number of technologies related to the production system are critical to deepwater development. These include unique structures design, materials development, and ocean floor foundation engineering. Innovative installation, maintenance, and repair techniques are important for structures, risers, and deepwater pipelines. Drilling, well control, and well completion are also important to deepwater development. Human diving capability is currently limited to about 1,640 feet, although there have been experimental dives to 2,300 feet. Both one-atmosphere manned vehicles and remote-controlled unmanned vehicles will be increasingly used for construction, maintenance, monitoring, and repair of equipment. Deepwater pipeline systems will involve adaptation of conventional pipelaying techniques and new approaches to overcome problems of buckling caused by long unsupported span lengths, higher strain levels, and severe sea states.

Offshore Safety

Special safety risks are present in oil and gas development in offshore frontier regions because of the harsh environments and remote locations. In general, the safety record of offshore operations appears equal to or better than the record of comparable onshore industries. **Still, there may be a need for new approaches to preventing work-related injuries and fatalities in coping with new hazards in the hostile Arctic and deepwater frontiers.** The oil and gas industry has the primary responsibility for ensuring the safety of offshore operations and is governed by a complex system of regulations. Both the Coast Guard and MMS enforce regulations controlling aspects of workplace safety.

The possibility of catastrophic rig accidents is the greatest concern in offshore frontier areas. Such incidents have occurred in the past because of storms, structural failures, and capsizings. Other fatalities have been caused by well blowouts, explosions, and fires. Currently, there is no regulatory requirement for the submission of integrated safety plans which address technical, managerial, and other aspects of the safety of offshore operations. In addition, insufficient funding by the Federal Government may result in inadequate rig safety inspections and monitoring efforts. Comprehensive safety plans, increased regularity of government monitoring efforts, and improved inspection techniques to match the increasing complexity and sophistication of offshore facilities may be needed.

Environmental conditions in frontier regions also present unique problems in evacuating personnel from rigs and platforms. Conventional lifeboats and rafts cannot be used on ice or in remote locations. Free-falling boats, air-cushioned vehicles, special aircraft or helicopters, and icebreaking ships may be needed to evacuate personnel from rigs. It has been proposed that appropriate standby vessels be required by law to be stationed near offshore facilities. The adequacy of evacuation measures could be assured by evacuation performance requirements, regular inspections, and evaluation of evacuation drills.

Since offshore accidents are most frequently caused by human errors rather than by equipment failures, there are limits to safety improvements possible through purely technical means. To achieve some improvement in human performance, responsibility for safety could be delineated more clearly and better defined chains of command could be established. More extensive and improved work force training also may be necessary for operations in hostile frontier regions.

There is currently no single comprehensive source of statistics on offshore injury and fatality rates. The lack of integrated data makes it difficult to evaluate the level of safety achieved by the offshore oil and gas industry or to assess the effects of safety regulations and equipment on the industry's safety performance. Improved population and injury data collection systems, greater consistency among data sources, and centralization of data collection and analysis in a single government agency could aid in evaluating the effectiveness of safety measures. Offshore safety data systems could be improved to include comprehensive event and exposure data; to relate events to specific employers, locations, operations, and equipment; to calculate frequency and severity rates and analyze trends; and to permit monitoring of the relative safety performance of owners and employers, locations, and activities.

Federal Offshore Services

The Federal Government provides a variety of services and information that bear on the development and protection of offshore resources. Government services most useful to the offshore oil and gas industry are those that support maritime operations, including research and development, weather information, navigation services, and icebreaking. The adequacy of these services for large-scale oil and gas development in offshore frontier areas, particularly the Arctic, is in question. There is also debate regarding the appropriate division of costs and responsibilities between the government and the private sector in the provision of offshore services.

The most significant government research and development program is the MMS Technology Assessment and Research Program, which focuses on the evaluation of offshore technologies with regard to safe operation and pollution avoidance. This program, which has almost been eliminated in past budget cuts, is the primary research activity supporting Federal regulatory efforts and deserves continued support. In 1984, Congress enacted the Arctic Research and Policy Act to facilitate the coordination of Arctic research. However, this Act does not contain authority for the appropriation of additional funds, and budget support for Arctic research must come from existing programs.

Federal programs providing weather and ice information and navigational services are generally considered marginal for increased industry activities in offshore frontier regions, but at the same time are targeted for budget cuts. The Administration has proposed shifting the responsibility for weather satellite services and coastal and bathymetric charting to the private sector. In addition, there are plans to phase out existing radionavigation systems and replace them with a single satellite system—the Global Positioning System (GPS). Despite the dependence of the oil and gas industry on accurate ice information, there are limitations on sensing equipment and significant voids in satellite coverage for a major part of the Arctic.

The proper role of the government in the provision of icebreaking services is also in question. Icebreaking will be essential to maintaining shipping lanes and drillship sites, protecting drilling operations from drifting ice, and aiding supply and logistics operations, oil spill response, and search and rescue. However, the U.S. Coast Guard, which would normally provide these services, has no plans for an Arctic facility. The closest Coast Guard facility to Point Barrow, Alaska, is now 400 miles to the south. While the Coast Guard will continue to meet its overall icebreaking obligations to the extent allowed by the budget, additional capacity may not be available to serve the expanding needs of the offshore petroleum industry.

ECONOMIC FACTORS

Exploration and development of oil and gas resources in Arctic and deepwater frontiers will result only if the promise of economic returns outweighs the associated high risks and costs. In general, higher costs and longer lead-times to production lower the profit margins of resource development in offshore frontier areas. As a result, the sensitivity of project economics to changes in various economic factors—e.g., costs, prices, and government payments—is higher in frontier areas than in mature producing regions such as the shallow areas of the Gulf of Mexico. The leasing and payment provisions of the OCS Lands Act Amendments of 1978 were based largely on experience gained from oil and gas leasing in State submerged lands and the Federal areas of the Gulf of Mexico and California.

OTA used a computer simulation model to analyze the economic attractiveness of oil and gas development under deepwater and Arctic conditions and to assess the implications of government policies. Cash flow profiles were developed for the four technology scenarios in the Navarin Basin, Harrison Bay, Norton Basin, and California deepwater, as well as for a more conventional project in the Gulf of Mexico.

Extremely large oil and gas discoveries are needed to offset the high costs and long timeframes of development in offshore frontier areas. While a 40- to 50-million barrel field may be highly profitable in the shallow-water areas of the Gulf of Mexico, some economic projects in the Alaskan offshore may depend on finding 1 to 2 billion barrels or more of recoverable reserves. Fields of this magnitude are called "elephants" by the industry and are extremely limited.

The OTA computer simulation indicated that government lease and tax payments affect the profitability of offshore fields differently in frontier areas than in other leasing areas. Fixed royalties tend to overtax small fields and remove the economic incentive for the development of resources. Bidding systems based on alternative types of lease payments may reduce the financial risks associated with frontier-area fields and provide greater incentive to the development of marginal resources.

In general, the profitability of oil and gas development in deepwater and Arctic regions will be affected by increases or decreases in real oil and gas prices. In the Alaskan region, the availability of economic market outlets for oil and gas—from the export of Alaskan oil and the development of processing and transportation systems for Alaskan natural gas—could improve the economic profile of offshore fields.

FEDERAL LEASING POLICIES

In the 1980s, the Department of the Interior accelerated the rate and extent of offshore leasing as a means of hastening exploration and development of energy resources. Secretary Watt initiated a system of "area-wide leasing," which expanded the offshore acreage considered for each lease sale. The number of lease sales to be held each year was increased, and the focus was on leasing in deepwater and Arctic frontier areas. However, the actual pace of offshore leasing in this period was constrained by opposition and conflicts. **Resolution of the issues surrounding area-wide leasing could allow the new 5-year leasing program (1986-91) to proceed more smoothly.**

Challenges to the area-wide leasing approach have been based on the adequacy of environmental information to support lease sale decisions. Other litigation stemmed from disagreements between Coastal States and the Federal Government over requirements that Federal offshore actions be consistent with State coastal zone management programs. Congress imposed moratoria on leasing in some areas, largely as a result of Federal-State disputes on the division of escrow money from jointly owned tracts, the failure to devise a mutually acceptable revenue-sharing formula, and coastal zone management issues. Because of these delays, only 7 of the 21 lease sales scheduled through the end of 1984 were held on the originally scheduled date.

The extent of offshore acreage offered for lease has also been constrained by military deferrals of areas for fleet operations, submarine transit lanes, missile flights, aircraft testing, underwater listening posts, and other uses. As offshore oil and gas activities have expanded into frontier regions, the possible incompatiblity between military and energy development uses in some areas of the ocean has become more obvious. Continuing deferrals may result in permanent withdrawals of OCS lands for military reservations. Such reservations could remove a significant amount of potentially productive acreage from oil and gas development. Currently, there is some confusion as to who has final authority for withdrawing acreage from oil and gas development—the Department of the Interior, Department of Defense, or Congress. If uncertainty in the frontier-area leasing process is to be reduced, this issue as well as questions regarding U.S. international boundaries in several frontier regions and the exact delimitation of the U.S. Outer Continental Shelf eventually should be resolved.

In order to provide the necessary incentives for exploration and development in offshore frontier areas, it may be desirable to implement new leasing approaches or modify lease terms and conditions. There is general agreement on the need for longer lease terms for offshore deepwater and Arctic areas in view of the much longer period of time needed to explore and develop resources under hostile operating conditions. As leasing in offshore frontier areas has increased, more tracts have been offered and leased with 10-year rather than 5-year lease terms. However, specific criteria may be needed for extending lease terms. In addition, there should probably be a requirement for submission of exploration plans within a specified timeframe.

There is less agreement on the type of bidding systems appropriate to offshore frontier areas. The Department of the Interior prefers the traditional cash bonus bid with a fixed royalty system that has gained general acceptance from industry and is easy to administer. However, bidding variables other than the cash bonus and lease payments other than fixed royalties may be more suited to the economics and risks of frontier areas. Other countries leasing in frontier areas generally have used a more flexible work commitment system in conjunction with larger lease areas and longer lease terms. After discovery of oil or gas, government payments may be based on profits, on productivity of the tracts, or other variables that take into account the costs and risks of development. More analysis and testing are needed before any attempts at implementation of these systems on a broad basis.

ENVIRONMENTAL CONSIDERATIONS

The development of offshore oil and gas resources and protection of the environment are potentially conflicting objectives and the subject of continuing debate. Nevertheless, the OCS Lands Act Amendments of 1978 require that energy and environmental policy goals be balanced in offshore development. Other Federal laws provide additional environmental safeguards. Major environmental considerations related to the development of Arctic and deepwater areas include trends in the Department of the Interior's Environmental Studies Program, the status of the endangered bowhead whale and other marine mammals, and the adequacy of oil spill containment and cleanup techniques.

The OCS Lands Act directs the Department of the Interior to systematically study the environmental components that may be affected by offshore development. The MMS Environmental Studies Program includes research on the distribution and population dynamics of marine species, the fate and effect of oil spills, and general ecosystem processes. Overall funding for the Environmental Studies Program has been decreasing at a nearly constant rate since 1978. The MMS maintains that a great deal has been learned about the offshore environment in the past 10 years of the program, and that substantial additional research may not now be warranted. However, OTA believes that the projected pace of leasing in the relatively unknown deepwater and Arctic regions and the need to monitor and regulate post-lease exploration and development activities may require more rather than less study of environmental effects.

Although many species of fish, marine mammals, and birds may be affected by oil and gas development, bowhead whales have received the most attention in recent years. Controversies surrounding the bowhead whale demonstrate the complexity of managing and protecting marine animals. Bowhead whales, which are classified as an endangered species, could be adversely affected by offshore oil and gas operations in the Arctic. Bowhead whales hold special meaning for the native Alaskan Inuit and Yupik people, and they serve as a supplementary food source for native people throughout much of the Arctic region. In addition, whales are involved in the politics of the international conservation movement and come under the scrutiny of the International Whaling Commission.

In comparison to funds spent on studying other endangered species, a large proportion of available funds has been spent on bowhead whale research. Despite this, most scientists are reluctant to make unqualified statements concerning population, reproduction, or the effects of oil and noise on the animals. Four major areas are targeted for more research: 1) bowhead whale population estimates; 2) the effects of noise on whales; 3) the long-term cumulative effects of industrial activities on whales; and 4) identification of critical habitats for bowheads.

Although the risk of catastrophic oil spills from offshore operations is believed to be low, effective containment and cleanup measures are essential in light of the potential harmful effects of any such spill. The offshore oil and gas industry is genuinely concerned and has diligently prepared for dealing with the eventuality of oil spills. Industry has invested large amounts of funds and effort in engineering technology to prevent blowouts and other catastrophic rig accidents. Considerable costs for cleanup and damage claims could be associated with a large spill. Some claim, however, that there is little market incentive for developing oil spill countermeasures compared to spill avoidance.

For the most part, oil spill containment and cleanup technology has been developed for spills in nearshore and temperate regions. It may not be suitable for use under the extreme conditions of deepwater and the Arctic. Arctic oil spill countermeasures may be complicated by extremely cold temperatures, the presence of ice, long periods of darkness, intense storms, and lack of transportation and storage facilities in most areas. In deepwater areas, high sea-states may be encountered, and greater distances from shore may create logistical problems for oil spill cleanup. To date, it has not been demonstrated in a real situation that industry will be able to use effectively the existing oil spill equipment and countermeasure strategies in hostile environments.

ISSUES AND OPTIONS

Little is known about the actual resource potential of the offshore lands of the United States. Experts believe that major new oil and gas supplies may be located in the Arctic and deepwater frontiers. The country will need this oil and gas to fill energy requirements at the end of the century—a mere 15 years away. The history of petroleum exploration suggests that large fields are generally discovered early in the exploration cycle. Even if major resource discoveries are made by the end of the next 5-year leasing program in 1991, the Nation will still have serious decisions to make about its energy future. The offshore oil and gas industry may need incentives to reenter the frontier areas for a "second-round" of exploration of the promising but smaller oil and gas prospects.

OTA has identified policy options for expediting exploration and development of oil and gas in deepwater and Arctic offshore regions and for providing additional incentives to the industry. OTA has also outlined options for protecting environmental values and increasing offshore safety in conjunction with exploration and development activities. These issues and options should be considered by Congress in the review of the next 5-year leasing program (1986-91), which will place emphasis on leasing in offshore frontier areas.

Energy Planning and Offshore Resources

The goal of the offshore leasing program is to increase the Nation's energy supply, thereby reducing dependence on oil imports. The offshore frontier areas are believed to have the greatest potential for major new domestic oil and gas discoveries. In the next few years, most of the remaining prospective areas of the offshore frontier regions will be considered for leasing. Substantial exploration has already occurred in some offshore frontier areas, such as the Gulf of Alaska and Atlantic regions. However, except in the Gulf of Mexico and California nearshore areas, exploration thus far has added very little to proven reserves. Accurate knowledge of the resource potential of the Nation's offshore areas is critical to overall energy planning and to making decisions about the offshore leasing program and alternative energy programs. In order to effectively plan for future energy needs, the Nation may need to reevaluate the role and resource potential of offshore areas when the findings of additional exploratory drilling in offshore frontiers are available.

Congressional Options

Option 1: Reassess available information about the resources of the OCS with regard to the potential of offshore oil and gas in supplementing the Nation's future energy supplies in the context of National Energy Planning.

Action: Establish a Congressional Commission or request an existing body (e.g., National Research Council, National Petroleum Council) to reassess the role of offshore oil and gas in the Nation's energy future at some point in the next 5-year leasing schedule.

Area-Wide Leasing

Exploration and development of oil and gas resources in offshore frontier areas can be encouraged by more rapid and efficient leasing of offshore acreage. The system of area-wide leasing initiated by the Department of the Interior in 1983 has increased the pace of leasing with the hope of early identification of resources. Area-wide leasing permits the industry to select from among the full range of available tracts in deepwater and Arctic regions and to explore those of greatest resource potential. However, the greater size and faster pace of lease offerings under the area-wide system may reduce the detailed consideration of environmental concerns, competing land uses, and State and local views in the leasing process. A return to the previous tract nomination system could allow for greater outside input into the leasing process, but may slow determination of the resource potential of offshore frontier areas.

Congressional Options

Option 1: Allow the Secretary of the Interior to determine the size of lease offerings in offshore frontier areas.

Action: No action required by Congress.

Option 2: Direct the Secretary of the Interior to use a "tract nomination system" for lease offerings in offshore frontier areas.

Action: Amendment to OCS Lands Act or congressional directive through the appropriations process.

Military Use Conflicts

As exploration and development have expanded to offshore frontier regions, there has been increasing conflict between oil and gas activities and military uses of offshore areas. An estimated 40 to 55 million acres of offshore land are restricted from oil and gas development for military and national security purposes, and as much as 75 million additional acres are affected by restrictions on the density of oil and gas operations. Deferrals and exclusions of lease tracts for military reasons are now negotiated by the Department of the Interior and the Department of Defense. Past disagreements on offshore land uses have prompted a review of this procedure and have led to a new memorandum of understanding between the agencies. While the OCS Lands Act gives authority for withdrawal of offshore acreage for national defense purposes to the Secretary of Defense, the Withdrawal of Lands for Defense Purposes Act reserves this authority for Congress. Continuing confusion over who has final authority to withdraw offshore acreage adds uncertainty to the leasing process and may delay exploration in offshore frontier areas. A procedure is needed which resolves the conflicting authorities and adequately balances energy and military uses of offshore lands.

Congressional Options

Option 1: Allow Secretary of the Interior and Secretary of Defense to continue negotiating military withdrawals of OCS acreage.

Action: No action required by Congress.

Option 2: Delegate authority for military withdrawal of OCS acreage to one department.

Action: Amendment to OCS Lands Act and/or amendment to Withdrawal of Lands for Defense Purposes Act.

Option 3: Reserve authority for military withdrawal of OCS acreage to Congress.

Action: Amendment to OCS Lands Act.

Disputed International Boundaries

Contested international boundaries eventually may contribute to delays in oil and gas exploration. There are unresolved disputes between the United States and other countries in several offshore frontier regions, including those with the Soviet Union in the Bering Sea and with Canada in the Beaufort Sea. A dispute between the United States and Canada over Georges Bank was recently arbitrated by the International Court of Justice, but important bilateral management issues are yet to be worked out. In addition, the outer boundary of the extensive U.S. continental shelf has not been delimited, and uncertain jurisdiction in the central Gulf of Mexico may eventually cause tension between the United States, Mexico, and possibly Cuba. Although there is no immediate need to resolve contested boundaries, such disputes could be settled through bilateral negotiation, arbitration, or mediation. Arrangements could be made for joint exploration and/or development of contested areas by the parties to the dispute. Contested offshore areas could also be withdrawn from oil and gas development pending settlement of disputes. Resolution of offshore boundary questions would help reduce international tensions and allow exploration and development of frontier areas to proceed in an orderly manner.

Congressional Options

Option 1: Allow arbitration by the International Court of Justice to resolve boundary disputes.

Action: Congressional directive to Department of State to negotiate arbitration agreements with other countries.

Option 2: Establish an interim arrangement for exploration and/or development of disputed offshore areas.

Action: Congressional directive to Department of State to negotiate appropriate agreements.

Option 3: Create buffer zones in disputed areas where no oil or gas development would take place.

Action: Congressional directive to Department of State to negotiate appropriate agreements.

Lease Terms[1]

Longer lease terms may be needed in offshore frontier areas to allow sufficient time for exploration and identification of resources. The standard 5-year lease term for offshore tracts has been increased to 10 years for many tracts in deepwater and Arctic areas under the authority provided to the Secretary of the Interior in the OCS Lands Act. However, the lack of specific criteria for 10-year lease terms adds uncertainty to the offshore leasing process in Arctic and deepwater frontier areas. In addition, 10-year lease terms in deepwater now are provided only for tracts in water deeper than 900 meters or 2,950 feet. An established policy on 10-year lease terms and a more realistic deepwater threshold may be needed. The Department of the Interior has proposed automatic 10-year lease terms for all tracts in water deeper than 400 meters or 1,320 feet. Currently, companies with 10-year leases have no set deadline for the submission of exploration plans and may hold a lease for 8 or 9 years before filing a statement of intention to explore. In conjunction with a longer lease term policy, the Department of the Interior may need to ensure diligent exploration in frontier areas by requiring submission of exploration plans at a specific time in the lease term (e.g., fifth or sixth year).

Congressional Options

Option 1: Establish automatic 10-year lease terms for tracts in water depths greater than 400 meters or 1,320 feet and for selected Arctic regions.

Action: Congressional directive to Department of the Interior through the appropriations process.

Option 2: Establish automatic 10-year lease terms for selected offshore frontier areas and include provisions for submission of exploration plans within a specific time period.

Action: Congressional directive to Department of the Interior through the appropriations process.

Alternative Bidding Systems

The United States has traditionally allocated offshore tracts on the basis of the highest cash bonus bid with a fixed royalty payment. The OCS Lands Act Amendments of 1978 mandated testing of several alternative bidding systems. However, after testing, the Department of the Interior prefers the traditional system. This bidding system is easy to administer, has promoted efficient exploration and development of offshore tracts in conventional leasing areas, and has been accepted by both government and industry. However, there may be disadvantages in using this system to allocate offshore frontier tracts. The requirement for upfront cash bonus payments may be a deterrent to continued exploration of frontier areas, because these areas involve greater uncertainty and far higher costs. Alternative arrangements such as "work commitment leases" may be needed to sustain activities in high-risk deepwater and Arctic regions. In addition, because of low profit margins in frontier areas, fixed royalties may overtax small fields and lead to nondevelopment of resources. Bidding systems with other types of lease payments, such as sliding scale royalties, net profit shares, or even zero royalties, may provide more incentives to marginal resource development. Effective implementation of alternative bidding systems, however, will require additional experimentation, analysis of costs and benefits, and adjustments in other lease conditions such as the size of the lease tracts.

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[1] MMS has extended lease terms for deepwater tracts (*Federal Register*, Apr. 3, 1985). Tracts in water depths between 400 and 900 meters will have 8-year terms, and tracts in waters deeper than 900 meters will have 10-year terms. To ensure exploration diligence, exploration drilling is required during the first 5 years.

Congressional Options

Option 1: Allow the Secretary of the Interior to select the bidding system to be used in offshore frontier areas.

Action: No action required by Congress.

Option 2: Direct the Secretary of the Interior to continue testing alternative bidding systems in offshore frontier areas.

Action: Amendment to OCS Lands Act.

Alaskan Oil Export Ban[2]

Removing the ban on exporting oil produced in offshore Alaskan areas could provide an added economic incentive to developing offshore resources in the Arctic. In the 1970s, concern about the Nation's increasing oil import dependence prompted Congress to place restrictions on the export of oil produced on Alaska's North Slope and in offshore areas. About half of the oil produced on the North Slope is now shipped to Gulf of Mexico and Atlantic Coast refining centers. Exporting oil to closer markets in Japan and other Asian countries could reduce transportation costs and increase the profits of producing Alaskan oil. The increased profit margins on offshore fields could improve the incentives for developing marginal resources in Alaskan offshore areas. However, removing the export ban could have economic and national security costs as a result of increased dependence on imported oil and adverse effects on domestic shipping which heavily depends on the Alaskan tanker trade. In addition, it is not certain that export markets in Japan could be established.

Congressional Options

Option 1: Remove restrictions on exporting oil produced in Arctic offshore regions.

Action: Amendment to Export Administration Act.

Option 2: Evaluate advantages and disadvantages of exporting Alaskan oil, with reference to economics of Alaskan offshore oil production and market development.

Action: Establish an Alaskan Oil Export Commission to make recommendations on exporting Alaskan oil.

Environmental Information

The Environmental Studies Program administered by the Minerals Management Service is the major research program on the effects of oil and gas development on offshore environments. This information is used in preparing Environmental Impact Statements and as an aid to the Secretary of the Interior in weighing the costs and benefits of offshore development. The Environmental Studies Program is changing its emphasis in the Alaskan region from acquiring pre-lease information to acquiring post-lease data needed for management of oil and gas activities. Funding for the program, however, has been decreased and led to a reduction in both pre-lease and post-lease studies. Proportionally, the decrease in funds for the Alaskan regions has been greater than that for temperate coastal areas. In general, decreases in the Environmental Studies Program budget are not justified in view of the relative lack of understanding of Arctic and deepwater marine environments, the projected pace of leasing in frontier areas, and the continuing need to monitor offshore oil and gas activities.

Congressional Options

Option 1: Allow Secretary of the Interior to determine the allocation of research funds for environmental studies of different offshore regions.

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[2] The House of Representatives passed a 4-year extension of the Export Administration Act, which contains restrictions on the export of Alaskan oil, on Apr. 16, 1985.

Action: No action required by Congress.

Option 2: Review funding levels for environmental studies in offshore frontier regions in light of new 5-year leasing schedule.

Action: Conduct congressional hearings on Environmental Studies Program and oversight review. Appropriate additional funds if found necessary.

Oil Spills

The offshore oil and gas industry has a good record of preventing oil spills. However, it has little experience in containing and cleaning up oil spills in offshore frontier environments, where there is now little oil production. Most current technology was developed for nearshore and inshore areas and may not be suited to frontier areas characterized by severe wind and waves, ice, extended periods of darkness, and/or low temperatures. Industry has directed its investments primarily to oil spill prevention rather than containment and cleanup, and government funding for oil spill technology research has been low. The OHMSETT (Oil and Hazardous Material Simulated Environmental Test Tank) Interagency Technical Committee has conducted limited testing of Arctic oil spill countermeasures technology, but budget constraints may reduce future testing. Government evaluation and publication of oil spill equipment test results could provide incentives to industry to improve countermeasures technology. Certain performance requirements might also encourage the industry to develop new technology and engineering approaches for dealing with oil spills.

Congressional Options

Option 1: Increase funding for research on oil spill countermeasures technology in offshore frontier areas.

Action: Increased appropriations to OHMSETT, MMS, Environmental Protection Agency, National Oceanic and Atmospheric Administration, and/or U.S. Coast Guard oil spill research programs.

Option 2: Develop a program for oil spill equipment testing and publication of results.

Action: Congressional directive to Department of the Interior through the appropriations process.

Option 3: Establish performance standards for industry oil spill response capability.

Action: Amendment to OCS Lands Act and/or congressional directive to Department of the Interior through the appropriations process.

Offshore Safety

The hostile operating conditions in deepwater and Arctic areas may require greater attention to personnel safety concerns during oil and gas activities. New technological approaches, management practices, and monitoring efforts may be needed to ensure high safety standards in offshore frontier regions. Improved Minerals Management Service and Coast Guard monitoring and inspection of offshore facilities could assure minimum safety standards and uniformity of safety conditions. Concern about possible catastrophic rig accidents has prompted proposals for better evacuation procedures and techniques, regular evacuation drills, and requirements for standby vessels. Regulations concerning work force training and management safety practices may need to be reviewed and revised for frontier areas. In addition, it is difficult to evaluate the seriousness of offshore safety hazards because of incomplete and inconsistent safety data. Implementation of Federal safety responsibilities in offshore frontier areas will require adequate and accurate data in order to monitor safety performance and the effectiveness of safety initiatives.

Congressional Options

Option 1: Increase funding for MMS and/or U.S. Coast Guard safety inspection programs in offshore frontier areas.

Action: Congressional directive through the appropriations process.

Option 2: Establish standards for evacuation procedures from fixed platforms and mobile drilling vessels in offshore frontier areas and periodically monitor emergency evacuation drills.

Action: Congressional directive through the appropriations process or Amendment to OCS Lands Act.

Option 3: Consolidate responsibility for collecting, analyzing, and reporting safety-related data in a single agency (MMS or U.S. Coast Guard).

Action: Congressional directive through the appropriations process or Amendment to OCS Lands Act.

U.S. Coast Guard Programs

The capacity of the U.S. Coast Guard to effectively conduct its missions in Arctic regions is limited and will be increasingly inadequate as offshore oil and gas development proceeds. Due to the current lack of activities in northern Alaskan offshore areas, U.S Coast Guard operations in Alaska are concentrated in the Gulf of Alaska, far to the south of the prospective Arctic oil areas in the Bering, Chukchi, and Beaufort Seas. The lack of an operational Coast Guard facility in the Arctic greatly impedes the agency's capabilities for search and rescue, vessel and platform safety inspection, law enforcement, maintenance of navigation, oil spill cleanup response, and icebreaking. Despite the potential for greater human safety and environmental risks in the region as a result of the increase in oil and gas activities, the Coast Guard currently has no plans for basing equipment and personnel in Arctic areas. However, studies of a potential Arctic facility are underway.

Congressional Options

Option 1: Establish a U.S. Coast Guard base in the Arctic region.

Action: Congressional directive through the authorization/appropriations process.

Ice Information

Arctic oil and gas operations depend on timely information about the location and movement of sea ice. Weather conditions and remoteness of facilities potentially make satellite imagery a very useful source of information on ice conditions. However, U.S. Arctic satellite-sensing capability is limited by the number of satellites and the capabilities of existing sensors. In addition, the usefulness of ice information obtained from satellites is reduced by the length of time needed for processing and delivery to users. Planned improvements in U.S. satellite systems will increase ice-related coverage of Arctic areas and contribute to the safety and efficiency of Arctic oil and gas development. Use of data from European and Canadian satellites could also assist offshore activities. However, there are uncertainties as to the timing and extent of improvements in U.S. satellites, the availability of information from foreign satellites, and the means for making satellite information available to the private sector. The Navy/NOAA Joint Ice Center, which has primary responsibility for processing and disseminating satellite ice data, could be upgraded to provide more timely operational data. In the absence of improved government ice data collection and distribution, the industry will have to place greater reliance on private sector ice information services.

Congressional Options

Option 1: Upgrade U.S. satellite system to improve ice data for oil and gas operations.

Action: Congressional directive through the appropriations process.

Option 2: Increase government acquisition of ice information from foreign polar satellite systems.

Action: Congressional directive through the appropriations process.

Option 3: Expand ice information processing and dissemination by the Joint Ice Center.

Action: Increased appropriations for the Navy/NOAA Joint Ice Center. Establish the Center permanently through authorizing legislation.

Government Information Services

Improved coordination and delivery of government information could facilitate operations in offshore frontier areas. Information and data relating to offshore oil and gas activities are now divided among several government agencies, including the Minerals Management Service, the National Oceanic and Atmospheric Administration, the U.S. Coast Guard, the U.S. Navy, and the Environmental Protection Agency. Users of offshore technical, environmental, and leasing information often find it difficult to identify agency contacts and sources of information within the government. The centralization of information services within a single agency has been proposed, but this would be difficult to implement in view of the contrasting responsibilities of the various agencies. NOAA has established a system of national ocean service centers, including an Anchorage, Alaska, center for the Arctic offshore area, which may provide a prototype for other agencies. These service centers act as regional clearinghouses for environmental and meteorological information gathered by NOAA. Other agencies, separately or in coordination with NOAA, could establish similar regional clearinghouses for information distribution to the offshore oil and gas industry.

Congressional Options

Option 1: Establish regional clearinghouses to collect and distribute government information relating to offshore oil and gas operations.

Action: Congressional directive through the appropriations process.

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The Role of Offshore Resources

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Chapter 2

The Role of Offshore Resources

OVERVIEW

The petroleum and natural gas resources of offshore areas of the United States could be a key additional energy source to help meet U.S energy needs and limit oil import growth in future years. Although plentiful energy supplies and declining world prices have dampened concern about the energy situation, supply and demand trends indicate potential domestic shortfalls and rising oil imports by the end of the century. At present, offshore oil accounts for about 11 percent of total domestic petroleum production and offshore natural gas accounts for about 24 percent of total domestic gas production. The potential for increasing the contribution of offshore areas to U.S. energy supply may be large. Most U.S. offshore acreage remains to be explored, and the search is just beginning in the deepwater and Arctic frontier areas.

Resource recoverability is determined by a combination of geologic, technologic, and economic factors which can change over time. In addition, petroleum resource statistics are confusing because each estimate seems to be the result of different definitions and statistical methods. Given the inaccuracy and uncertainty associated with published resource estimates, they probably should be considered only as indicators of relative ranking among prospective oil and gas producing areas.

Offshore areas are expected to contain 21 to 41 percent of the oil and 25 to 30 percent of the natural gas that is undiscovered and recoverable in the United States. As much as one-third to one-half of the offshore oil may lie under waters 660 to 12,000 feet deep. If onshore and offshore Alaska are considered together, Alaska may contain as much as one-half of the total amount of recoverable oil expected to be found in the United States. About 31 percent of the natural gas expected to occur offshore probably lies in water depths between 660 and 8,200 feet. Gas occurring in the Arctic offshore regions is now considered to be uneconomical to recover.

California, while having a long history of offshore petroleum production, still remains largely unexplored in many areas. Similarly, the Atlantic and Alaskan regions have had only limited exploration, and as yet their Federal offshore areas have no oil or gas production. The Gulf of Mexico region continues to produce about 90 percent of the oil and virtually all of the natural gas produced from submerged lands.

U.S. ENERGY OUTLOOK

Although the United States is now in a period of relative stability as far as energy prices and supplies are concerned, energy trends include slowly increasing demand, declining domestic production, and rising imports to the end of the century. Although oil imports have decreased in the last 5 years, domestic demand is outpacing supply and leading to higher import levels. Low oil and gas prices have reduced incentives to conserve on energy uses and to substitute alternative fuels. Forecasts indicate that imports could reach record highs in the 1990s, increasing U.S. vulnerability to supply disruptions. Against this background, the oil and gas resources of the offshore areas of the United States take on new significance in their potential contribution to future U.S. energy needs.

Energy Demand Trends

U.S. energy demand decreased over the past decade largely because of the increase in the price of oil and natural gas that began in the early 1970s and the resulting energy conservation efforts (see table 2-1). The real increase in the price of both

Table 2-1.—Energy Demand and Domestic Supply: 1978-83

Energy demand

Year	Oil (MMBD)	Natural gas (TCF)	Coal (MMT)	Nuclear (BkWh)	Hydro (BkWh)	Total (QUADS)
1968	13.4	18.6	509.8	12.5	225.2	60.9
1971	15.2	21.8	501.6	38.1	273.1	67.8
1974	16.7	21.2	558.4	114.0	316.9	72.5
1977	18.4	21.7	625.3	250.9	241.0	76.2
1980	17.0	19.9	702.7	251.1	300.1	75.9
1983	15.2	17.0	736.7	293.7	373.2	70.7

Domestic energy production

Year	Oil (MMBD)	Natural gas (TCF)	Coal (MMT)	Nuclear (BkWh)	Hydro (BkWh)	Total (QUADS)
1968	10.6	18.5	556.7	12.5	225.9	56.7
1971	11.2	20.2	560.9	38.1	269.5	61.2
1974	10.5	20.7	610.0	114.0	304.2	60.8
1977	9.9	19.2	697.2	250.9	223.6	60.1
1980	10.2	19.4	829.7	251.1	279.2	64.7
1983	10.3	16.0	784.9	293.7	332.1	61.2

SOURCE: Energy Information Administration, *1983 Annual Energy Review*, DOE/EIA-0384 (83), Washington, DC, April 1984.

fuels was about 250 percent between 1972 and 1983. In the same period, energy use per unit of gross national product dropped more than 22 percent. In the industrial sector, energy demand declined by 15.5 percent as a result of increased energy efficiency in various industrial processes and a shift to less energy-intensive products. In the residential and commercial sectors, energy demand remained nearly constant due to building insulation efforts and reduced heating and cooling levels. In the transportation sector, driving mileage has been reduced, and fuel consumption has become more efficient since the Corporate Average Fuel Economy (CAFE) standards were put in place.

Today, a combination of stable energy prices and recovery from the 1982-83 economic recession has caused demand to grow once again. Total energy demand in 1984 increased about 7 percent over 1983. Most of the increase is probably to restore demand capacity lost during the recession. There are indications, however, that fuel-use efficiency may be dropping. Driving mileage is up and automobile manufacturers are producing and selling more cars with lower fuel economy. Just as higher prices prompted fuel conservation, it appears that lower petroleum prices may now be encouraging greater energy use.

There is also less incentive to switch from oil and gas to alternative fuel sources. After the oil and gas price increases of the 1970s, demand for alternative fuels grew. Electric utilities, in particular, made greater use of coal and nuclear power in place of oil and natural gas. However, low oil and gas prices have now reduced the economic advantage of using coal, and the future of nuclear power is limited unless changes are made in the technology, management, and regulation of the industry. Low oil prices have halted the development of synthetic fuels made from more abundant resources (e.g., coal, oil shale, heavy oils, tar sands). Similarly, the high capital costs of converting direct renewable energy sources (e.g., solar, wind, wood) has severely limited their potential for replacing oil and gas.

Energy forecasts indicate that overall U.S. energy demand will grow modestly to the end of the century and that oil will remain the largest single energy source. Projections by the Department of Energy (DOE) and the Gas Research Institute (GRI) show energy consumption in the United States growing by about 1 percent per year—less than half the expected growth rate of the gross national product (see table 2-2). The percentage of oil used in relation to total energy use is forecast to be about 35 percent in 2000 as compared to 42

Table 2-2.—U.S. Energy Demand and Supply Forecasts to 2000

Energy source	Demand GRI	Demand DOE	Domestic supply GRI	Domestic supply DOE	Imports GRI	Imports DOE
Oil and NGL (MMBD)	16.7	15.2	9.2	8.1	7.5	7.1
Natural gas (TCF)	19.0	18.7	15.9	15.9	3.8	2.8
Coal (MMT)	1,345.0	1,190.0	—	—	—	—
Nuclear (BkWh)	600.0	700.0	—	—	—	—
Hydro (BkWh)	375.0	375.0	—	—	—	—
Other (Quads)	2.9	3.3	—	—	—	—
Total (Quads)	93.3	90.9				

SOURCES: *1984 GRI Baseline Projection of U.S. Energy Supply and Demand, 1983-2000*, Gas Research Institute, Chicago, IL, October 1984; U.S. Department of Energy, *Energy Projections to the Year 2010*, DOE/PE0029/2, Washington, DC, October 1983.

percent today. This decline does not represent any significant replacement of oil, but rather indicates that growth in the electric utility sector will continue to be accommodated partly by coal and nuclear power.

Energy Supply Trends

Despite the large oil and gas price increases of the 1970s, domestic energy production remained virtually level over the past decade (see table 2-1). Growth in the production of coal and nuclear power offset declines in domestic oil and natural gas production. If the contribution of Alaskan crude oil production is removed, domestic oil production declined more than 18 percent between 1974 and 1983. The slight increase in domestic oil production since 1980 is due entirely to production from the Prudhoe Bay Field on Alaska's North Slope. Domestic oil and gas reserves have declined even more rapidly than production, despite enormous increases in resource exploration and development since 1973, and particularly since 1980. According to DOE, proven reserves of economically recoverable oil dropped from 47 billion barrels in 1970 to 35 billion barrels in 1984.

As a result of the recent increase in energy demand, however, domestic energy production increased in 1984 as compared to 1983. Crude oil production grew slightly with increases in Alaskan production, and natural gas output was about 11 percent ahead of 1983. Coal production, which declined between 1981 and 1983, was up sharply as electricity demand rebounded from the recession. Similarly, the production of nuclear-generated electricity was expanded in 1984, as new power plants came on line.

Oil import levels have increased as growth in domestic demand has outpaced domestic oil production. Oil imports decreased after the oil embargo and price increase of 1973, but shortly thereafter grew to an all time high of 9.3 million barrels per day in 1977. Over the next 2 years, Alaskan oil began to flow in significant quantities and U.S. imports of petroleum declined slightly. A second oil price rise in 1979 and cumulative conservation efforts led to declining imports and a record oil import low of 4.9 million barrels per day in 1983. However, in 1984, oil imports once again started to climb and increased about 7 percent over 1983, accounting for about one-third of U.S. petroleum requirements.

The DOE and GRI energy forecasts indicate a continuing decline in the production of domestic oil and natural gas to the year 2000 (see table 2-2). In both forecasts, oil and gas imports are expected to increase substantially, to between 7.1 and 7.5 million barrels of oil per day and 2.8 and 3.8 trillion cubic feet (Tcf) of natural gas per day. There are indications, however, that even the DOE and GRI projections may be optimistic and that imports may reach higher levels. Continued low energy prices may lead to greater fuel usage, reduced conservation efforts, and limited replacement of oil by alternative fuels. There are also uncertainties about natural gas supplies and the possibility that price controls and a failure to develop unconventional sources may promote substitution of oil for natural gas.

In comparison with the DOE projection of 8.1 million barrels per day and the GRI projection of 9.2 million barrels per day, studies by the Office of Technology Assessment (OTA)[1] and the Congressional Research Service (CRS)[2] forecast even greater declines in domestic production of crude oil. OTA projected that domestic oil and natural gas liquids production would decline to 4 to 7 million barrels per day by 2000. CRS was less pessimistic, but still estimated a decline in production to 7.3 to 8.5 million barrels per day. These production levels indicate that oil imports may range from 7 to as high as 10 million barrels per day in 2000, contributing to high trade deficits and decreases in energy and economic security.

Current energy forecasts underline the importance of the oil and gas resources of the U.S. Outer Continental Shelf (OCS) and the Exclusive Economic Zone (EEZ). Since domestic reserves have been dropping over the last several years, an increasing percentage of our domestic oil production must come from oil reserves as yet undiscovered. Widespread exploration and development of the lower 48 States make large field discoveries in onshore areas of the United States, outside Alaska, somewhat doubtful. In contrast to the overall energy reserve status in the United States, estimated recoverable oil and gas reserves in Federal offshore areas have increased steadily in recent years. However, only a small percentage of total U.S. offshore area has been explored. Offshore resources, particularly those of the unexplored deepwater and Arctic frontier regions, offer the best hope for limiting future U.S. energy import dependence.

RESOURCE PROJECTION PROBLEMS

The U.S. Geological Survey (USGS) estimated in 1981 that 26 to 41 percent of the oil and 25 to 30 percent of the natural gas that is undiscovered and recoverable in the United States would be found offshore within the EEZ. However, that estimate is by no means certain. Published projections of oil and gas reserves and resources are generally incomplete and lack accuracy. There are several reasons for this.

- Projections of oil and gas resources are generally based on averages or aggregated values from independent analyses and expert opinions, which results in widely ranging estimates that are subject to large errors.
- Until an area is sufficiently explored, resource projections are largely inferred from indirect geological information, e.g., seismic records, gravity and magnetic data, and geomorphology, and Continental Offshore Stratigraphic Test (COST) wells.
- Information on oil and gas reserves in existing fields and assessments of resource potential for frontier regions are considered by the petroleum industry to be proprietary and highly sensitive, therefore it is unlikely that precise, detailed information on recoverable reserves and resources from individual firms will be available to Congress, the Department of the Interior, or the public.

The amount of recoverable oil and gas that remains to be discovered beyond the currently estimated reserves will be produced from two sources: 1) extension of known fields through new developments in drilling technology and new techniques for increasing (enhancing) oil and gas recovery from old fields; and 2) new discoveries in unexplored frontier regions and undeveloped areas of proven regions.

Over three-fourths of the oil discovered thus far in the United States is located in "giant" fields of 100 million barrels or more—e.g., the Gulf of Mexico and Prudhoe Bay, Alaska. About 8 percent of the discovered oil is found in fields smaller than 10 million barrels. Therefore, the reliability of discoverable resource projections for the EEZ will depend on how well geologists and petroleum engineers can predict the existence of giant fields offshore, and how accurately they can evaluate the extent of the recoverable resources that lie therein.[3] When estimates go beyond proved reserves, accuracy rapidly deteriorates with errors of perhaps 50 percent or more.

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[1] U.S. Congress, Office of Technology Assessment, *World Petroleum Availability: 1980-2000* (Washington, DC: U.S. Government Printing Office, October 1980).

[2] Congressional Research Service, "Domestic Crude Oil Production Projected to the Year 2000 on the Basis of Resource Capability" (July 1984).

Comparability Among Estimates

Although resource estimates may be useful to Congress in considering national policies, their value lies primarily in indicating the relative reserve potential from the likely petroleum-bearing basins rather than as estimates of absolute quantities of oil and gas available offshore. The primary use of published resource assessments is for general information.

Published sources have little technical use in either the administration of the offshore leasing program by the Department of the Interior or the formulation of industry leasing strategies. Firms make large investments to develop detailed information on resource prospects in the individual basins of the OCS for the purpose of corporate planning. Good resource information is a major competitive factor among oil and gas firms bidding on offshore tracts, and therefore is considered proprietary. However, it is unlikely that even the industry has *accurate* estimates.

Four independent assessments of the oil and gas resources of the OCS are currently available to the public:

1. USGS Circular 860 (1981): *Estimates of Undiscovered Recoverable Conventional Resources of Oil and Gas in the United States.*
2. National Petroleum Council (1981): *U.S. Arctic Oil and Gas.*
3. Rand Corporation (1981): *The Discovery of Significant Oil and Gas Fields in the United States.*
4. Potential Gas Committee (1983): *Potential Supply of Natural Gas in the United States.*

It is difficult to make area-by-area comparisons of the estimates of undiscovered oil and gas published in the four resource assessments. The difficulty in comparing these estimates arises from: 1) differences in methodologies used in deriving the resource estimates; 2) differences in reporting statistical data, e.g., errors, ranges, and probabilities; 3) inconsistencies in definitions of resources and reserves; 4) differences in technical and economic assumptions in deriving recoverable resource values; 5) the inclusion or exclusion of unconventional resources, e.g., low permeability formations; 6) lack of agreement on boundaries (water depth, international boundaries, etc.) of the resource area being estimated; and the fact that 7) the professional perspectives of the estimators may influence the probabilities assigned to the estimates; and 8) the conditions and assumptions on which the estimates are based are seldom specified in sufficient detail.

Furthermore, several government agencies with varying missions often report resource statistics in different ways to suit their particular purpose. This may result in inconsistencies among government reports and add to the confusion.

Reliability of Estimates

It is difficult to determine the reliability and credibility of the various resource assessments for many of the same reasons. In addition: 1) details of the methods used for estimating resources are not published; 2) data bases and geological information used for the assessments are often considered to be proprietary and confidential; and 3) the process used for deriving resource estimates relies largely on the "expert opinion" of geologists and petroleum engineers.

While it is not entirely accurate to characterize the collective (averaged) judgment of resource experts as "subjective," the use of "opinions" in lieu of science-based hypotheses and experimental data prevent these expert-derived estimates from being considered wholly "objective."

There can probably, therefore, be no determination as to which resource assessment is the "best" or "most accurate." In any oil and gas resource assessment, the quantitative volumes should be considered speculative and may or may not accurately reflect the volumes of oil and gas that will or could be ultimately discovered in any single basin or region. Many of the basins with large estimated potential may prove unproductive; some may yield petroleum recoveries exceeding even the most optimistic estimates. Estimates are made recognizing the uncertainties involved, but are based on the current level of knowledge.

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[3] M. King Hubbert, "Techniques of Prediction as Applied to the Production of Oil and Gas," *Oil and Gas Supply Modeling*, S. I. Grass (ed.) (Washington, DC: National Bureau of Standards Special Publication 631, May 1982).

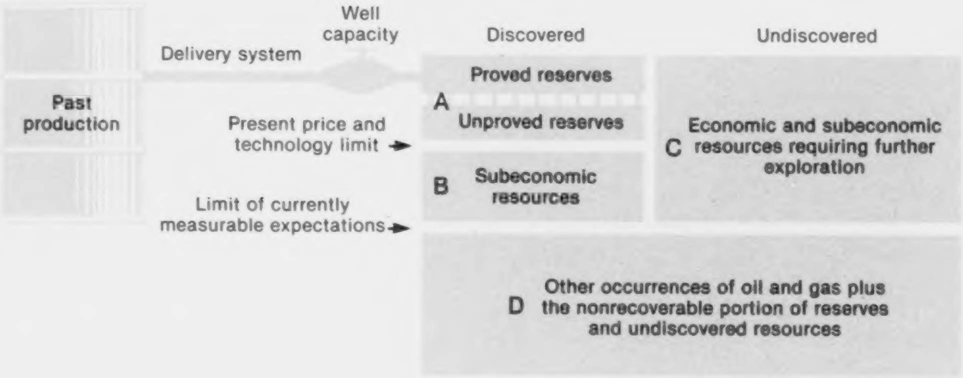
Interpretation of Estimates

Aside from problems of comparability and reliability, there are problems associated with interpreting various estimates. Statistics for potential oil and gas resources are reported using a lexicon that may confuse and befuddle those unfamiliar with petroleum resources. Petroleum reserves and resources are frequently explained, as shown in table 2-3.

In addition, crude oil and natural gas resources are often reported in combined units of "barrels of oil equivalent (BOE)." This measure is calculated by converting estimated natural gas and natural gas liquids to oil (product) equivalents based on comparable energy (Btu) units. While BOE resource statistics provide a common unit of measure which is easily communicated and comparable, it can be misleading where natural gas production is not immediately planned.

For example, the National Petroleum Council (NPC) study reports a risked mean of 31 billion BOE in Arctic offshore basins. However, only 57 percent (18 billion barrels) is oil, and the balance is gas and natural gas liquids. In remote regions of the Arctic and in many deepwater areas, natu-

Table 2-3.—Definitions of Reserves and Resources


Well capacity
Delivery system
Discovered
Undiscovered
Past production
Proved reserves
A
Unproved reserves
Present price and technology limit
Economic and subeconomic resources requiring further exploration
C
B
Subeconomic resources
Limit of currently measurable expectations
D
Other occurrences of oil and gas plus the nonrecoverable portion of reserves and undiscovered resources

Reserves: Oil and gas which has already been found and is considered producible under current prices using currently available technology.

Proved Reserves: Immediately producible portions of the oil and gas reserves that will flow from wells in developed reservoirs and the quantity of which can be estimated accurately.

Unproved Reserves: Oil and gas that has been discovered but cannot be estimated with as great accuracy and may require additional drilling and development.

Subeconomic Resources: Oil and gas that has been discovered, but in the judgment of the operators cannot be produced under current prices with existing technology. Subeconomic resources are sometimes divided into two portions: First, the unrecoverable, high-cost portion of oil and gas currently left behind in producing reservoirs. Second, oil and gas in other reservoirs that have been found but are not now producing or have been abandoned because they would cost too much to produce due to size or other problems.

Economic and Subeconomic Resources Needing Further Exploration: Oil and gas that remains to be discovered. Exploratory drilling has not proceeded to a point where there is physical evidence of the actual presence of oil and gas. Only expectation exists, and estimates of undiscovered oil and gas are based solely upon geologic and engineering extrapolations.

Other Occurrences: Oil and gas left behind that is not expected under any future circumstances to be worth the effort or cost of production, as well as deposits which are considered too small to find or to produce if found. Other forms of petroleum may be included in this category, e.g., oil shale, tar sands, heavy oils, etc.

SOURCE: John J. Schanz, Jr., "Oil and Gas Resources — Welcome to Uncertainty," in *Resources* (Washington, D.C.: Resources for the Future, March 1978).

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ral gas production is not now economically feasible. Therefore, to combine oil and natural gas into a single measure can be misleading to those not familiar with the distinction between oil equivalent resource statistics (which may include unmarketable natural gas) and crude oil resource statistics.

Other Factors

Estimates of potentially recoverable resources will change in response to: 1) oil prices, production costs, and economic conditions; 2) new technological developments that enable more efficient recovery of oil and gas; and 3) new knowledge about resources gained from exploration. For example, the USGS revised its 1975 resource estimates in 1981 to reflect changes in technology (resource estimates were included down to water depths of 7,870 feet in Alaska and 8,200 feet elsewhere); changing economic conditions; and more geological information gained from exploration. As a result, estimates of offshore oil potential decreased slightly even with the additions from the Continental Slope. Offshore oil resources were estimated at 17 to 49 billion barrels in 1975 and decreased to 17 to 44 billion barrels in 1981. Estimates of natural gas increased significantly from 42 to 81 Tcf in 1975 to 72 to 167 Tcf in 1981.

U.S. EXCLUSIVE ECONOMIC ZONE

The 200-nautical mile U.S. Exclusive Economic Zone encompasses 1.9 billion acres adjacent to the coasts of the continental United States.[4] Approximately 1.3 billion acres of the EEZ is underlain by the Continental Shelf, the extension of the continental land mass that was flooded when the oceans rose. Almost half of the U.S. Continental Shelf (815 million acres) lies adjacent to Alaska.

Along most of the U.S. coastline, the Continental Shelf gradually slopes downward (see figure 2-1) until it breaks abruptly at the edge of the Continental Slope where it plunges steeply toward the deep ocean floor. At the transition zone between the deep ocean and the base of the Continental Slope is the Continental Rise, which rises gradually from the Abyssal Plain.[5]

Water depths over the Continental Shelf range to more than 600 feet at the edge of the Continental Slope. Undersea canyons have been cut deeply into the Continental Shelf at the mouths of major rivers, such as the Hudson, the Mississippi, and off the mouth of the Chesapeake Bay. The Continental Slope plunges to depths over 8,250 feet before merging with the Continental Rise. Depths over the Continental Rise range between 11,500 and 20,000 feet.

Much of the Continental Shelf was formed under prehistoric conditions that favored the evolution of petroleum—accumulated organic-rich sediments, extremely high pressures from overlying materials, and high subsurface temperatures. Thirty-four sedimentary basins with oil and gas potential have been identified in the U.S. Continental Shelf. The Department of the Interior recognizes 26 offshore areas with commercial oil and gas potential for purposes of leasing in the OCS. Sediments in some of these basins reach thicknesses of more than 43,000 feet. In addition, portions of the Continental Slope and the Continental Rise are underlain by a great wedge of sediments and ancient buried reefs that may contain petroleum deposits. Deep oceanic basins, particularly the Gulf of Mexico, may also contain petroleum, but because of the water depths much less is known about these prospects.[6]

The breadth of the U.S. Continental Margin (Shelf, Slope, and Rise) varies considerably, ranging from a few miles along steep segments of the Pacific Coast to perhaps 500 miles adjacent to parts of Alaska. The establishment of the U.S. EEZ in

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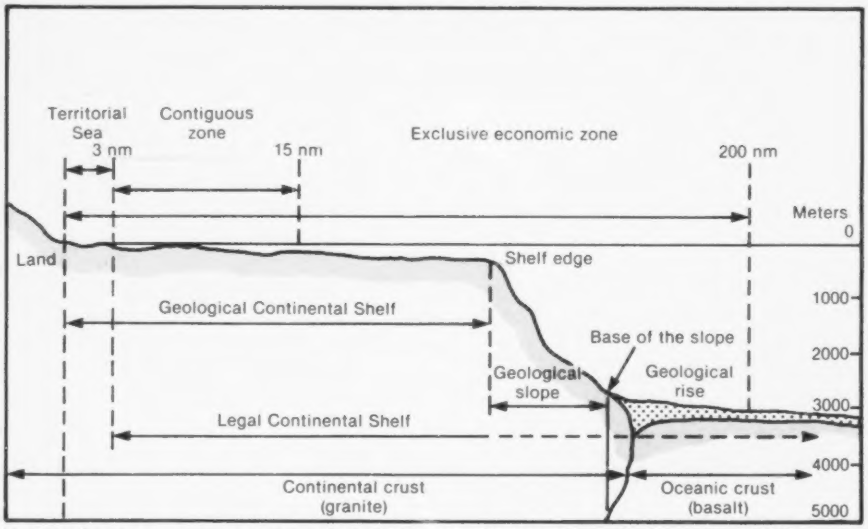
[4] Robert W. Smith, "The Maritime Boundaries of the United States," *Geographical Review* (October 1981), p. 395.

[5] One should distinguish between the "geologic" Continental Shelf and the "legal" Continental Shelf. The former is defined by scientific principle of landform, position and geological origin. The latter is a construct of law imposed by the need for regulating international affairs among coastal nations under the Law of the Sea and international agreements.

[6] H.D. Hedberg, U.D. Moody, and R.M. Hedberg, "Petroleum Prospects of the Deep Offshore," *AAPG Bulletin* 63(3):286-300.

Figure 2-1.—Profile of Physiographic Features of the Geological Continental Margin of the U.S.


Territorial Sea
3 nm
Contiguous zone
15 nm
Exclusive economic zone
200 nm
Meters
0
Land
Shelf edge
1000
Geological Continental Shelf
Base of the slope
2000
Geological slope
Geological rise
3000
Legal Continental Shelf
4000
Continental crust (granite)
Oceanic crust (basalt)
5000

SOURCE: Robert D. Hodgson and Robert W. Smith, "The Informal Single Negotiating Text (Committee II): A Geographical Perspective," *Ocean Development and International Law Journal 3:3.*

1983 added about 46 percent more ocean area to that already under the jurisdiction of the United States for the purpose of exploring and developing the living and nonliving resources of the sea. The net effect was to add approximately 600 million acres of seabed to that already claimed for exclusive resource development by the United States offshore the 50 States.

Oil Resources

The two most widely quoted assessments of offshore oil resources are USGS Circular 860 and the NPC study. The NPC study dealt only with Arctic resources and, in general, there is some agreement between the two assessments on Arctic oil potential. Both assessments used an averaging technique (modified Delphi) to aggregate expert opinion of estimates based on "geological analogies," i.e., the prediction of the occurrence of oil in an unexplored area based on similarities between that area and one in which oil is known to exist.[7] However, because the statistical treatment of the data is different in the two assessments, the estimates can not be directly compared.

Resource estimates from USGS Circular 860 are the most widely cited and have been used in the past by the Minerals Management Service (MMS) in general lease sale planning and for public information (see table 2-4). Total offshore oil resources according to the USGS study are about 30 billion barrels, one-third of which is in water depths greater than 660 feet (see figure 2-2). However, as a result of an institutional reorganization, the MMS no longer uses USGS estimates in lease sale planning. Henceforth, MMS will be responsible for developing all offshore resource estimates and has recently revised the estimates of offshore oil and gas (see box).[8]

Deepwater Oil Resources

According to the 1981 USGS estimates, about 40 percent of the recoverable oil expected to be found in the Continental Slope beneath water depths greater than 660 feet is in the Atlantic

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[7] Joseph P. Riva, Jr., "The Occurrence of Petroleum," *World Petroleum Resources and Reserves* (Boulder, CO: Westview Press, 1983)

[8] Minerals Management Service, *Estimates of Undiscovered Oil and Gas Resources for the Outer Continental Shelf* (personal correspondence, Feb. 4, 1985).

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Ocean. Nearly 25 percent of the projected deepwater oil resource is in the Pacific Ocean off California, Oregon, and Washington, and a like amount is expected to be found in deepwater regions of the Gulf of Mexico. Deepwater resources in Alaska are estimated to be about 1.1 billion barrels.

The USGS did not include recoverable oil and gas that may occur in deep ocean regions, e.g., the Gulf of Mexico Oceanic Basin or in extremely deep water in the Pacific Ocean, in its 1981 assessment. It is possible, therefore, that one-third to one-half of U.S. offshore oil resources lie under waters ranging in depth from 660 feet to more than 12,000 feet when the potential of the oceanic basins within the OCS is included.

Arctic Oil Resources

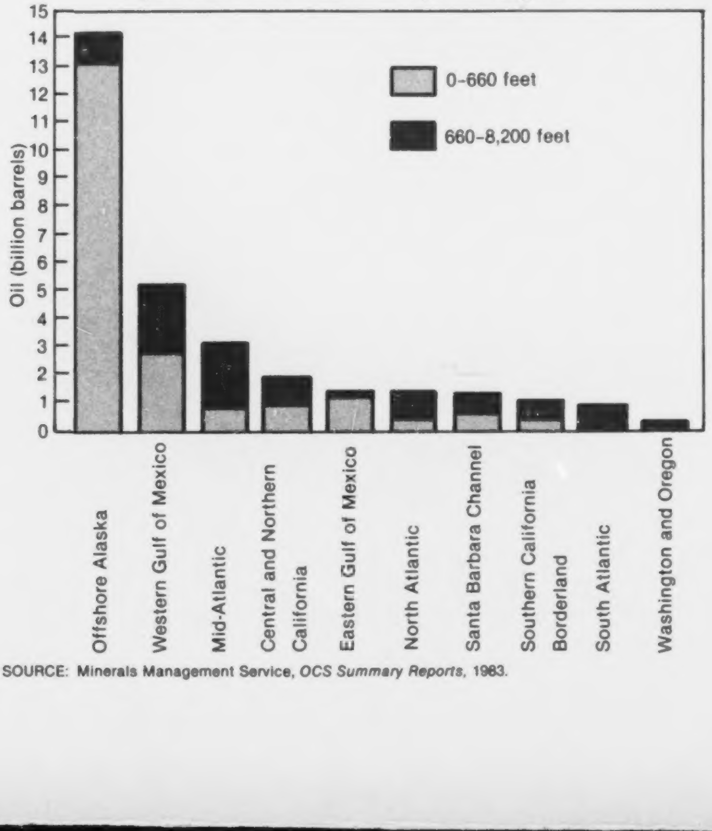
Resource estimates indicate that Alaska may contain about one-half of the recoverable oil (offshore and onshore) remaining in the United States. The NPC assessment estimates the mean undiscovered recoverable resource in the Arctic to be 18 billion

Table 2-4.—Offshore Resource Estimates

	Water depth (meters)	Oil (billion barrels)	Gas (TCF)
Alaska			
Norton Basin	(0-200)	0.2	1.2
St. George Basin	(0-200)	0.4	2.5
Navarin Basin	(0-200)	0.9	5.6
	(200-2500)	0.1	0
North Aleutian Basin	(0-200)	0.2	1.0
Beaufort Sea	(0-200)	7.8	39.3
	(200-2500)	0.8	4.3
Chukchi Sea	(0-200)	3.6	13.8
	(200-2500)	0.2	1.1
Gulf of Mexico			
Central and Western Gulf of Mexico	(0-200)	2.8	42.9
	(200-2500)	2.4	26.1
Eastern Gulf of Mexico	(0-200)	1.2	2.4
	(200-2500)	0.2	0.4
Pacific			
Southern California	(0-200)	1.0	1.3
	(200-2500)	1.4	2.6
Central and Northern California	(0-200)	0.9	1.0
	(200-2500)	1.0	1.3
Washington and Oregon	(0-200)	0.1	0.6
	(200-2500)	0.2	0.8
Atlantic			
North Atlantic	(0-200)	0.4	2.4
	(200-2500)	1.0	3.2
Mid-Atlantic	(0-200)	0.8	5.6
	(200-2500)	2.3	8.6
South Atlantic	(0-200)	0	0.2
	(200-2500)	0.9	3.6

SOURCE: Minerals Management Service, *OCS Summary Reports*, 1983, (based on *USGS Circular 860*, 1981).

Figure 2-2.—Oil Resources by Planning Area



SOURCE: Minerals Management Service, *OCS Summary Reports*, 1983.

OCS Oil and Gas Potential Downgraded

The Minerals Management Service provided OTA with revised resource estimates for offshore oil and gas in February 1985 as this study was concluding. The new estimates of undiscovered oil resources in the OCS lease sale planning areas are 55 percent lower than the USGS estimates published in 1981. Natural gas resources are 44 percent lower. The National Research Council is currently reviewing the methodology used by MMS in arriving at the revised offshore resource estimates, which were made for the 1986-91 5-year leasing program. Because of the substantial downgrading of offshore resource potential, OTA believes that the new MMS resource estimates should be critically considered for both their accuracy and the implications for U.S. energy policy.

A comparison of the risked mean estimates of the 1981 and 1985 assessments show decreases in potential undiscovered oil and gas resources in each of the offshore regions. Major reductions occur in the Alaska region, where oil resources are reduced 73 percent and gas resources 78 percent, and in the Atlantic region, where oil resources are reduced 87 percent and gas 48 percent. The resource estimates were lowered due to the failure to discover petroleum during exploratory drilling in these regions in the past five years. Lower resource estimates also result from reporting some resources as reserves in the Gulf of Mexico and Pacific regions, differences in methodology and assumptions, and changing economics and cost of production.

In arriving at the new estimates, MMS used a different analytical technique than that used by USGS and NPC in their 1981 resource assessments. The 1985 estimates are based on the PRESTO computer model (Probabilistic Resource Estimates—Offshore). The model requires geologists, engineers and economists to provide information about prospective volumes of oil and gas, their technical recoverability, and costs and prices of the produced petroleum. The previously used Delphi method relied on opinions and judgments of groups of experts, which were averaged by statistical means to obtain probabilistic estimates.

Atlantic

Exploration in the Atlantic has been disappointing. Two COST wells and eight exploratory wells in the North Atlantic did not yield discoveries. Boundary concessions to Canada east of Georges Bank further reduced prospects in U.S. waters. The most promising areas of the Mid-Atlantic have been drilled with two COST wells and 32 exploratory wells with only the discovery of uneconomical quantities of natural gas. Although the South Atlantic has not recently been drilled, one COST well and six exploratory wells yielded no discoveries in the past. Drilling at record-breaking depths over promising deepwater structures resulted in no discoveries.

Gulf of Mexico

The mature areas of the Gulf of Mexico region did not change significantly between the 1981 and 1985 estimates. The Central Gulf is the highest ranked area in the Gulf in terms of resource potential. The existence of transportation and services infrastructure makes the development of marginal fields profitable.

Pacific

The 1985 estimates for the Pacific Region are only marginally lower than the 1981 estimates. Over 300 wells have been drilled off California. As a result of major discoveries in Southern California, reserve estimates increased in 1983. After shifting resources to reserves, the California regions decreased 19 percent for oil and 18 percent for gas. The Oregon and Washington area has had 12 exploratory wells drilled without discoveries.

Alaska

Lower Alaskan estimates are largely attributed to unsuccessful exploration in that region since 1981. Six exploratory wells have been drilled in the Beaufort Sea (Diapir Field), and the only discovery thus far has been Shell's Seal Island Field. Drilling in the Norton Basin has consisted of two COST wells and two exploratory wells without a discovery. The Navarin Basin has had one COST well and one exploratory well without a discovery. Most of the successful drilling has been in State waters in southern Alaska. In Federal waters, one COST well and 12 exploratory wells have been drilled in the Gulf of Alaska without the discovery of a producing field. The Federal portion of Cook Inlet has had one COST well and nine exploratory wells without discovery.

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Revised Offshore Oil and Gas Resource Estimates

Planning area	Oil (billion barrels) 1981	Oil (billion barrels) 1985	Oil (billion barrels) % change	Gas (trillion cubic feet) 1981	Gas (trillion cubic feet) 1985	Gas (trillion cubic feet) % change
Alaska:						
Beaufort Sea	7.8	0.89		39.3	3.93	
Navarin Basin	1.0	1.30		5.6	1.58	
Chukchi Sea	1.6	0.54		13.8	3.02	
St. George Basin	0.4	0.37		2.5	3.47	
Norton Basin	0.2	0.09		1.2	0.43	
Other	1.2	0.11		2.2	1.42	
Total Alaska	12.2	3.30	−73	64.6	13.85	−78
Atlantic:						
North Atlantic	1.4	0.11		5.6	2.14	
Mid-Atlantic	3.1	0.35		14.2	6.02	
South Atlantic	0.9	0.22		3.6	4.04	
Other	—	—		0.3	0.11	
Total Atlantic	5.4	0.68	−87	23.7	12.31	−48
Gulf of Mexico:						
Western Gulf	5.2	1.90		65.4	26.76	
Central Gulf	—	3.72		—	30.69	
Eastern Gulf	1.0	0.41		2.8	2.19	
Total Gulf of Mexico	6.2	6.03	− 3	68.2	59.64	−13
Pacific:						
Northern California	0.5	0.25		0.9	1.12	
Southern California	2.4	1.54		3.9	2.42	
Central California	—	0.36		—	0.51	
Washington and Oregon	0.3	0.04		1.4	0.65	
Total Pacific	3.2	2.19	−31	6.2	4.70	−24
Total Offshore	27.0	12.2	−55	162.7	90.5	−44

SOURCE: U.S. Geological Survey, Circular 860, *Estimates of Undiscovered Recoverable Conventional Resources of Oil and Gas in the United States* (1981). Minerals Management Service, *Estimates of Undiscovered Oil and Gas Resources for the Outer Continental Shelf* (personal correspondence, Feb. 4, 1985).

barrels while USGS estimates a resource base of 11 billion barrels of crude oil (see table 2-5).

In terms of undiscovered potentially recoverable oil (based on 1981 technology), according to the NPC, the Beaufort Sea has the greatest resource potential in Alaska with 9.5 billion barrels (USGS estimated 7.8 billion barrels) including both the Continental Shelf and the Slope (see figure 2-3). The Navarin Basin ranks second in resource potential with 2.4 billion barrels (USGS estimated 0.9 billion barrels); third is the Central Chukchi Shelf (NPC estimated 1.7 billion barrels, USGS estimated 0.6 billion barrels); followed by the North Chukchi Shelf and Slope (NPC estimated 1.5 billion barrels, USGS estimated 0.8 billion barrels); and St. George Basin with 1.2 billion barrels (USGS estimated 0.4 billion barrels).

Table 2-5.—Comparison of Estimates of Alaskan Offshore Oil Resources

Oil Resources (billion barrels)

Water depth (meters)	NPC (risked mean) 0-200 M	NPC (risked mean) 200-2500 M	USGS (mean) 0-200 M	USGS (mean) 200-2500 M
Beaufort	8.2	1.3	7.0	0.8
Navarin	2.3	0.1	0.8	0.1
Central Chukchi	1.7	—	0.6	—
St. George	1.2	—	0.4	—
N. Chukchi	1.2	0.3	0.8	0.2
Bristol	0.6	—	0.2	—
Norton	0.3	—	0.2	—
Hope	0.2	—	0.0	—
Zhemchug	0.1	0.0	0.0	0.0
Aleutian	0.0	0.0	0.0	0.0
Umnak Plateau	0.0	—	0.0	—
St. Matthew - Hall	0.0	—	0.0	—

SOURCES: National Petroleum Council, *U.S. Arctic Oil and Gas*, 1981; U.S. Geological Survey, Circular 860, 1981.

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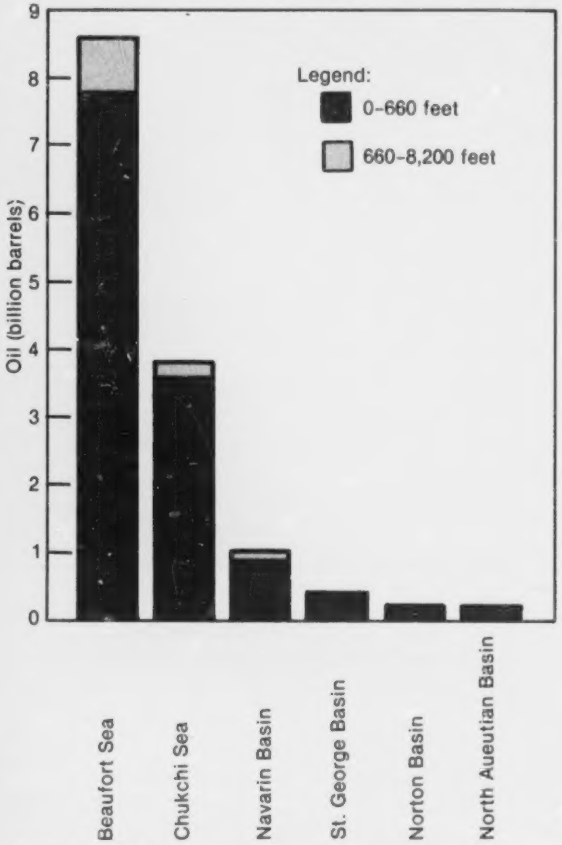
Figure 2-3.—Oil Resources in Alaska Planning Areas



SOURCE: Minerals Management Service, *OCS Summary Reports*, 1983.

Natural Gas Resources

The USGS estimates that the OCS contains about 172 Tcf of natural gas. The Potential Gas Committee (PGC), an industry-staffed group operating through the Colorado School of Mines, evaluated the natural gas resources that are expected to occur up to a maximum depth of 3,280 feet. It estimated that the OCS to that depth "probably" contains 35 Tcf of natural gas. (The PGC "probable" estimate is a modal estimate and may be comparable to the statistical mean.) Because the PGC assumed the economic limits of gas production to be about 3,000 feet on the Continental Slope, the USGS and PGC resource estimates for natural gas cannot be compared directly. It appears, however, that the PGC estimates are considerably more conservative than those of the USGS. Although the PGC has historically been optimistic about U.S. onshore natural gas resources, it estimates a probable potential offshore supply of 35 Tcf, a possible supply of 76 Tcf, and a speculative supply of 122 Tcf. Even its most optimistic estimate falls short of the USGS mean estimate of 172 Tcf. In waters 660 feet or less, the PGC estimates the probable occurrence of 32 Tcf of natural gas, while the USGS estimate is about 120 Tcf.

As more geological information is gained from exploratory drilling in frontier regions, natural gas estimates are revised upwards. In 1975, the USGS estimated that the Continental Shelf contained between 42 and 81 Tcf (at the 95 and 5 percent probability levels respectively) of natural gas. When revised in 1981, these estimates were increased to between 72 and 167 Tcf respectively. The upward adjustment resulted from indications of the presence of more gas and less crude oil in exploratory wells in the Atlantic, Gulf of Mexico, and Pacific offshore regions.

The Gulf of Mexico and the Alaskan Arctic are expected to contain nearly 82 percent of the natural gas in the OCS (72 and 70 Tcf respectively), while the Atlantic is estimated to contain 24 Tcf and the Pacific only 8 Tcf (see figure 2-4).

Deepwater Natural Gas Resources

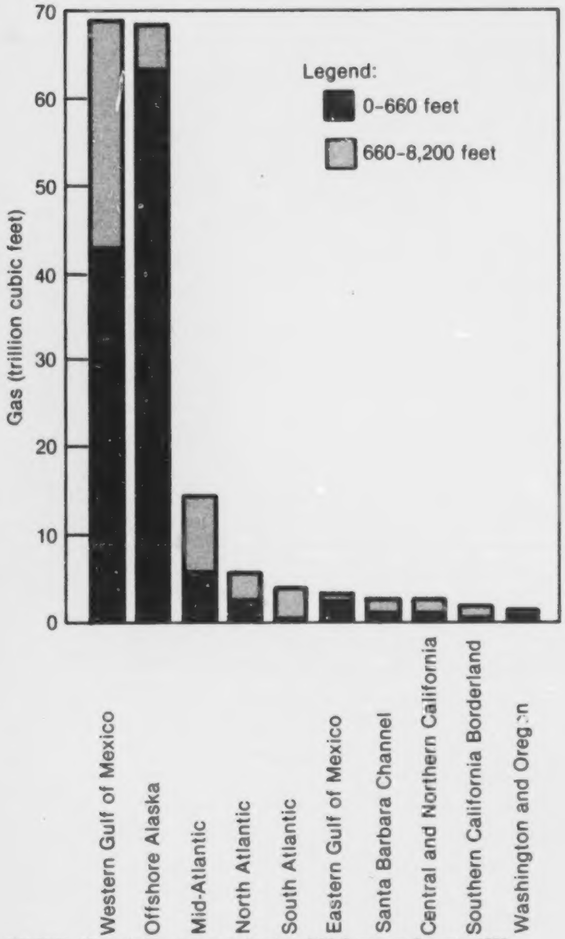
Approximately 31 percent of the natural gas in the OCS is expected to occur in water depths between 660 and 8,200 feet. About half of this (27 Tcf) is in the Gulf of Mexico, while 16 Tcf is in the Atlantic, 6 Tcf in the Arctic, and 5 Tcf in the Pacific.

Arctic Natural Gas Resources

The USGS estimates that 58 Tcf of natural gas may occur in the Arctic. The NPC estimates that 69 Tcf of natural gas may be expected to occur in that region (see table 2-6). The NPC estimate includes natural gas liquids while the USGS estimate does not. If natural gas liquids (2.5 billion barrels) are removed from the NPC estimate, the two assessments of Arctic natural gas potential agree within 20 percent.

Over 90 percent of Alaskan offshore gas lies in depths of less than 660 feet. The remote far north-

Figure 2-4.—Natural Gas Resources by Planning Area



SOURCE: Minerals Management Service, *OCS Summary Reports*, 1983.

ern regions of the Beaufort and Chukchi Seas are expected to contain about 78 percent (39 Tcf and 14 Tcf respectively) of the natural gas in the Arctic while the Navarin Basin contains 6 Tcf, St. George Basin 3 Tcf, and the Norton and North Aleutian Basins about 1 Tcf each (see figure 2-5).

Resources by Lease Sale Planning Areas

The EEZ is subdivided into 26 planning areas by the Department of the Interior for leasing purposes (see figure 2-6). Each planning area encompasses one or more sedimentary basins that have potential for petroleum resources. Nearly 1.1 billion acres of the total 1.9 billion acres within the OCS are included in the planning areas. However, only about 17 percent of the acreage (179 million acres) in the planning areas is considered to be underlain by "promising geological structures" with significant potential for accumulated oil and natural gas (see table 2-7).

Over half of the acreage (110 million acres) considered to have promising geological structures for oil and gas is adjacent to Alaska. About 15 percent (27 million acres) of the area over promising structures is in planning areas located in the Atlantic Ocean, where exploration activities have failed to confirm the presence of commercial quantities of oil or gas. A similar proportion of the promising geology (25 million acres) lies in the Gulf of Mexico planning areas which historically have produced large quantities of oil and natural gas.

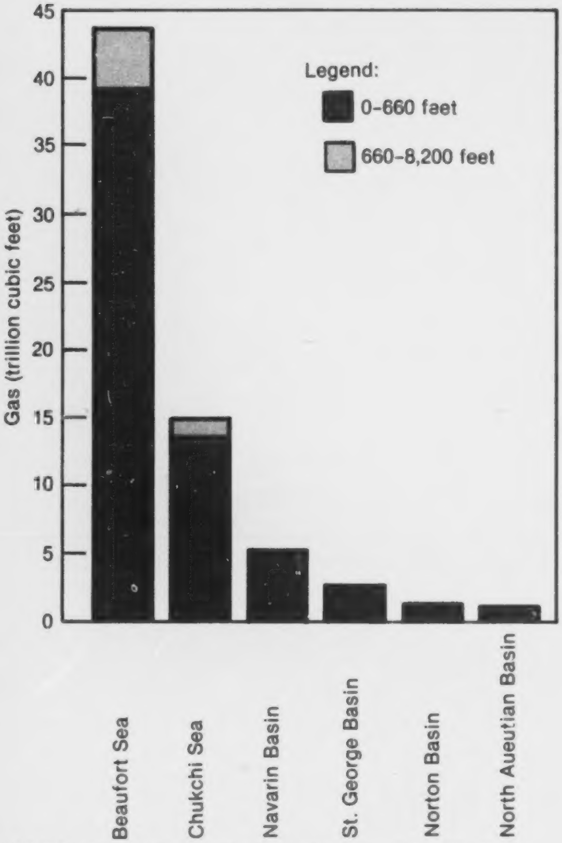
Table 2-6.—Comparison of Estimates of Alaskan Offshore Gas Resources

Gas Resources (trillion cubic feet)

	NPC (risked mean)		USGS (mean)	
Water depth (meters)	0-200 M	200-2500 M	0-200 M	200-2500 M
Beaufort	26.3	6.7	35.0	4.3
Navarin	9.5	<1.0	5.2	0.4
Central Chukchi	9.0	—	3.0	—
St. George	5.6	—	2.3	—
N. Chukchi	5.0	1.7	3.4	1.1
Norton	3.4	—	1.2	—
Hope	1.1	—	—	—
Bristol	0.3	—	1.0	—
St. Matthew - Hall	<1.0	—	0.0	—
Zhemchug	<1.0	<1.0	0.1	0.0
Umnak	<1.0	—	0.0	—
Aleutian	<1.0	<1.0	0.0	0.0

SOURCES: National Petroleum Council, *U.S. Arctic Oil and Gas*, 1981; U.S. Geological Survey, Circular 860, 1981.

Figure 2-5.—Natural Gas Resources in Alaska Planning Areas



SOURCE: Minerals Management Service, *OCS Summary Reports*, 1983.

Gulf of Mexico

The Gulf of Mexico region is the most extensively developed offshore region of the United States. It currently produces over 90 percent of total U.S. offshore oil production and virtually all of the offshore natural gas. The region consists of three lease planning areas: Western Gulf, Central Gulf, and Eastern Gulf. Projections indicate that the Gulf of Mexico will continue to dominate offshore oil and gas production as the industry expands its exploration into the deepwater frontier areas of the Gulf Oceanic Basin.

Exploration and development is most advanced in the Central Gulf of Mexico planning area, which lies south of the States of Louisiana and Mississippi. Thus far, little oil and gas activity has taken place in the Eastern Gulf of Mexico planning area adjacent to Alabama and Florida.

Table 2-7.—Estimates of Offshore Acreage With Hydrocarbon Potential (millions of acres)

Planning area	Geological structures*	Hydrocarbon potential**
North Atlantic	17.3	26.0
South Atlantic	9.4	63.2
Eastern Gulf of Mexico	6.0	58.0
Central Gulf of Mexico	9.4	46.0
Western Gulf of Mexico	9.3	35.0
Southern California	9.9	12.0
Central and Northern California	7.5	N/A
South Alaska (Gulf of Alaska, Kodiak, Cook, Shumagin)	2.0	148.4
North Aleutian Basin	3.2	12.4
St. George Basin	29.2	35.0
Navarin Basin	16.0	28.9
Norton Basin	7.5	8.9
Hope Basin	8.0	N/A
Chukchi Sea	14.0	29.7
Beaufort Sea	30.6	19.1
Total	179.3	522.6

*Estimates of the acreage covered by promising geological structures. Department of the Interior, Final Supplement to the Final Environmental Statement, Five-Year Lease Schedule, 1982.

**Estimates of the acreage having a potential for the generation, migration, and accumulation of hydrocarbons. Minerals Management Service, Resources Assessment Division, 1984.

Resource estimates. The Central Gulf of Mexico planning area is estimated to contain 3.2 billion barrels of oil and 34 Tcf of natural gas, which is more than half of the total undiscovered economically recoverable oil resources in the Gulf of Mexico region. The Western Gulf of Mexico planning area is expected to be rich in natural gas (26 Tcf), but contains only 2 billion barrels of oil. The Eastern Gulf of Mexico planning area is estimated to contain 1.2 billion barrels of oil and only 1.6 Tcf of natural gas. Remaining oil reserves in the Gulf of Mexico region are estimated to be 3 billion barrels of oil and 40 Tcf of natural gas.[9]

Physical and geological characteristics. The Continental Shelf in the Gulf of Mexico region slopes gently seaward at an angle of less than one degree It forms a broad plain of relatively shallow water ranging in breadth from 12 miles off the alluvia fan of the Mississippi River to as much as 140 mile off the mouth of the Crystal River in Florida. Th

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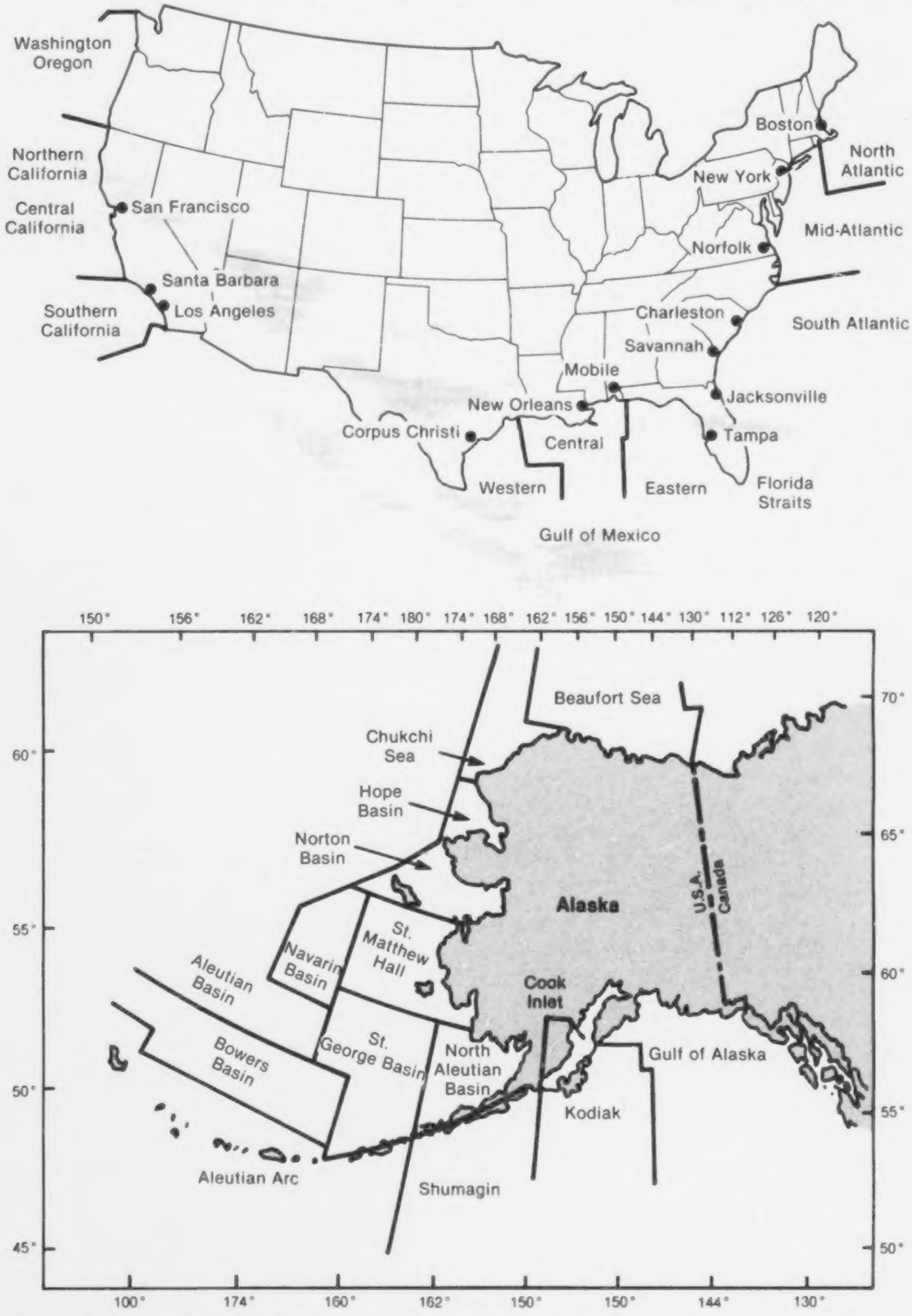
[9] Minerals Management Service, *Gulf of Mexico Summary Repo* (Washington, DC: U.S. Department of the Interior, September 1983 p. 8.

Figure 2-6.—Minerals Management Service Lease Sale Planning Areas


Washington
Oregon
Northern
California
Central
California
San Francisco
Santa Barbara
Los Angeles
Southern
California
Boston
New York
North
Atlantic
Mid-Atlantic
Norfolk
Charleston
Savannah
South Atlantic
Jacksonville
Mobile
New Orleans
Corpus Christi
Tampa
Central
Western
Eastern
Florida
Straits
Gulf of Mexico
150° 156° 162° 168° 174° 180° 174° 168° 162° 156° 150° 144° 130° 112° 126° 120°
Beaufort Sea
Chukchi
Sea
Hope
Basin
Norton
Basin
Alaska
U.S.A.
Canada
St.
Matthew
Hall
Navarin
Basin
Aleutian
Basin
Bowers
Basin
St.
George Basin
North
Aleutian
Basin
Cook
Inlet
Gulf of Alaska
Kodiak
Aleutian Arc
Shumagin
60°
55°
50°
45°
70°
65°
60°
55°
50°
100° 174° 160° 162° 150° 150° 144° 130°

NOTE: Maritime boundaries and limits depicted on the maps, and divisions shown between planning areas, are for initial planning purposes only.

SOURCE: Minerals Management Service.

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Continental Slope is relatively steep, ranging between 2 and 45 degrees. Beyond the base of the Continental Slope, the Abyssal Plain of the Gulf of Mexico Oceanic Basin reach depths of up to 12,000 feet at the outer edge of the EEZ. Although the Continental Shelf in the Gulf of Mexico region is extensive, 42 to 68 percent of the acreage within the Gulf of Mexico lease planning areas is in waters deeper than 660 feet (see figure 2-7).

Geological conditions that may occur in the Gulf of Mexico lease planning areas include unstable sediments on the sea floor, active faults, shallow gas accumulations, and underlying karst topography consisting of limestone caverns and voids in the seafloor. The area off the Mississippi Delta and along steeply sloping areas of the Continental Slope may be subject to mass sediment movements.

Leasing and exploration. The Gulf of Mexico is the most heavily explored and extensively developed offshore petroleum region in the world. The region has been explored for more than 50 years and has been producing oil and natural gas for more than 35 years. Nearly 21,000 wells have been drilled offshore in the Gulf of Mexico, most of them in the Central Gulf of Mexico planning area.

While exploration in the historically productive areas of the Central and Western Gulf of Mexico planning areas continues at a high level, the offshore industry's interest in deepwater tracts has also increased. The deepest exploratory well in the Gulf of Mexico was drilled in 1980 in the Mississippi Canyon in 2,210 feet of water, and several other wells have been drilled in waters ranging from 1,500 to 1,835 feet.

Several tracts leased in the Atwater Valley sector of the Central Gulf of Mexico planning area are in waters of 3,500 feet and deeper, and one block in the Port Isabel area of the Western Gulf of Mexico is in 3,500 feet of water.[10] Industry interest in deepwater tracts is centered on the area referred to as the "flexure play," a sloping deepwater site that rapidly descends at the edge of the Continental Shelf.

Development, production, and reserves. Crude oil production from the Gulf of Mexico region was about 310 million barrels in 1983, and natural gas production was approximately 3.9 billion cubic feet. Between 1972 and 1980, oil production in the Gulf of Mexico declined each year (see figure 2-8). This trend was reversed in 1981 and oil and condensate production is now at pre-1977 levels. The rebound in Gulf of Mexico oil production is considered to be an anomaly, however, and oil production is expected to soon resume its previous decline. Gas production may have reached its peak in 1981 and is also expected to begin a noticeable decline. At the beginning of 1984, Gulf of Mexico oil reserves were estimated at 3.4 billion barrels and natural gas at 43.7 Tcf.[11]

Atlantic

The Atlantic region, while one of the most geologically studied oceanic regions in the world, is considered to be a frontier region for oil and natural gas exploration. The region consists of four lease planning areas: North Atlantic, Mid-Atlantic, South Atlantic,and Florida Straits. There is no commercial crude oil or natural gas production from the Atlantic region, and no reserve estimates are available.

Resource estimates. Over three-quarters of the Atlantic region's undiscovered economically recoverable crude oil resources (4.2 billion barrels) and about two-thirds of its natural gas (15.4 Tcf) lie in water depths of 660 to 8,200 feet. Total undiscovered recoverable resources in the three lease planning areas of the Atlantic region are estimated to be 5.4 billion barrels of oil and 23.6 Tcf of natural gas.

Nearly 60 percent of the oil (3.1 billion barrels) and natural gas (14.6 Tcf) within the entire Atlantic region is expected to occur in the Mid-Atlantic planning area, between two-thirds and three-quarters of it in water depths between 660 and 8,200 feet. The North Atlantic planning area is estimated to contain 1.4 billion barrels of crude oil and 5.6 Tcf of natural gas, while the South Atlantic area is estimated to contain only 900 million barrels of crude oil—all in waters ranging in depth from 660 to 8,250 feet—and 3.8 Tcf of natural gas.

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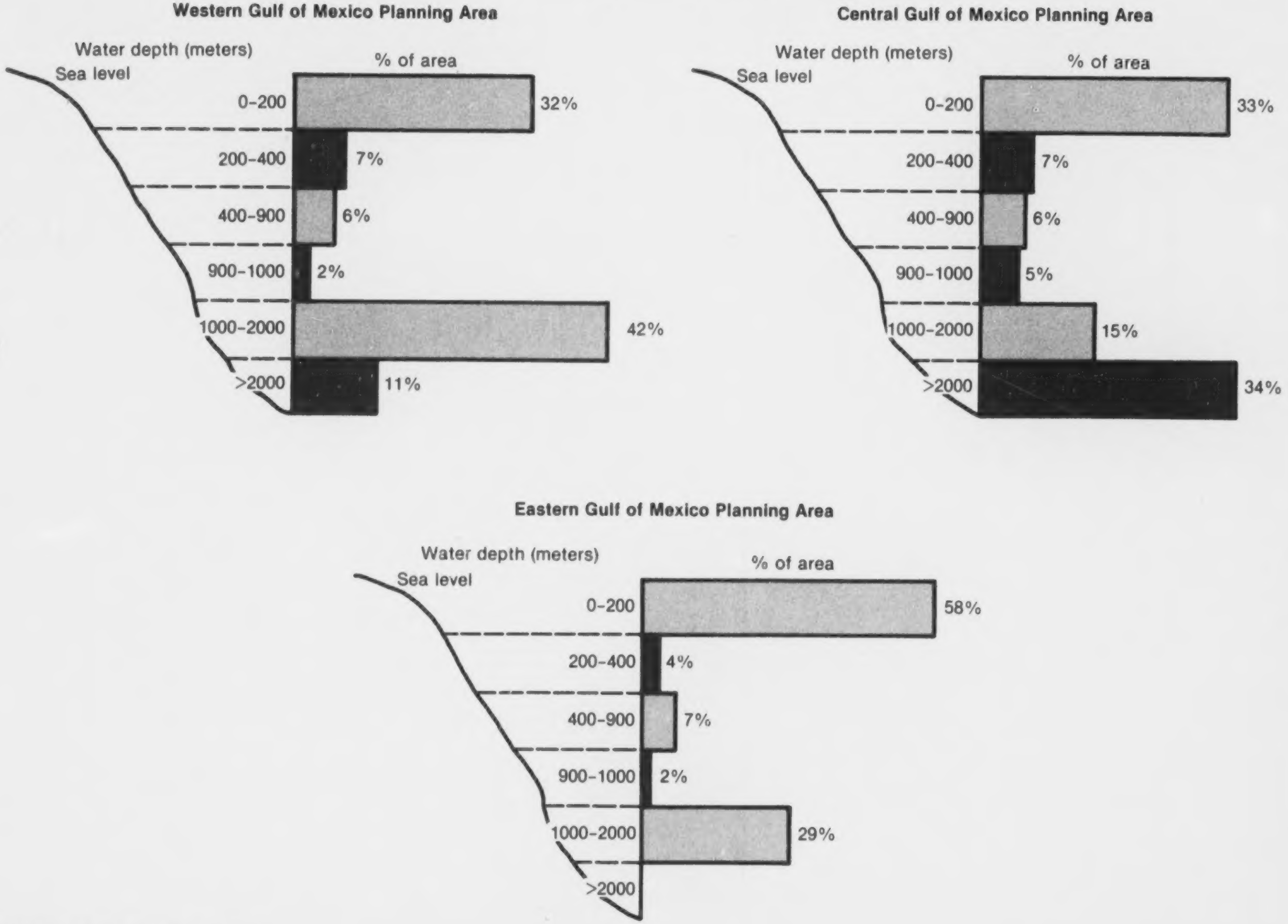
[10] Data Offshore Services, *Supplement to the Ocean Construction Report* (Houston, TX: Offshore Data Services, July 23, 1984).

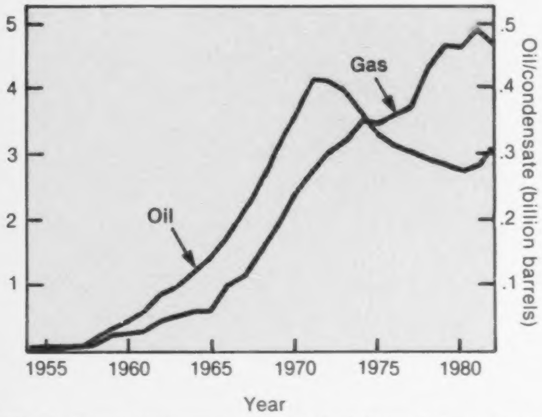
[11] Minerals Management Service, *Federal Offshore Statistics* (Washington, DC: U.S. Department of the Interior, 1984).

Figure 2-7.—Distribution of Gulf of Mexico Planning Areas by Water Depth



SOURCE: Office of Technology Assessment.

Figure 2-8.—Trends in Gulf of Mexico Oil and Gas Production



SOURCE: Minerals Management Service, *Gulf of Mexico Summary Report*, 1983.

Physical and geological characteristics. The Continental Shelf in the Atlantic region varies in width from 14 miles off Cape Hatteras to 200 miles off the coast of New England. From the break at the edge of the Continental Shelf to the base of the Continental Slope, water depths plunge to between 6,560 and 9,840 feet. From the base of the Continental Slope, the Continental Rise extends gradually seaward to depths of 16,405 feet in the Abyssal Plain of the oceanic basin at the outer edge of the EEZ.

The major geological feature of the North Atlantic lease planning area is the Georges Bank plateau on the eastern edge of the Continental Shelf off Cape Cod. About 58 percent of the waters within the North Atlantic planning area are 660 feet or less, and 35 percent are 6,560 feet or deeper (see figure 2-9).

Deep canyons intersect the Continental Slope in the Atlantic region. The Baltimore Canyon Trough is a major physiographic feature of the Mid-Atlantic planning area, extending 300 miles from northeast to southwest. It appears likely that the area of greatest hydrocarbon potential in the Atlantic region is located in the deeper waters of the Continental Slope of the Mid-Atlantic planning area, where a possible extension of Mexico's Reforma-Chiapas oil-bearing reef complex may be buried under mile-deep ocean sediment. Seventy-eight percent of the area within the Mid-Atlantic lease planning area is overlain by waters deeper than 6,560 feet.

The South Atlantic area is dominated by the Blake Plateau, a broad gently sloping segment of the Continental Shelf off Florida and Georgia, and the Carolina Trough, a steep sloping segment of the Continental Slope trending from northeast to southwest off North and South Carolina. Over two-thirds of the South Atlantic lease planning area is in water depths of 6,560 feet or deeper.

Geological conditions that may affect oil and natural gas development in the Atlantic region include: shallow recent faults, shallow gas deposits, mass movement of sediments, filled channels, erosion and scour, sand waves, faults present below the unconsolidated sedimentary section, and gas-charged sediments.[12] The northerly flowing Gulf Stream also may affect exploration and development of oil and gas in areas influenced by its currents.

Leasing and exploration. The first Atlantic region sale was held in the Mid-Atlantic lease planning area in 1976. Exploration in the Atlantic region peaked in 1979. Since that time, the disappointing results of earlier tests coupled with general economic conditions and worldwide petroleum markets has slowed the pace of the offshore industry's exploration efforts.

Pacific

The Pacific region is considered the cradle of the offshore oil and gas industry in the United States. In the 1890s, numerous shallow wells were drilled from wooden piers along southern California beaches. From these piers, the offshore petroleum industry ventured onto offshore platforms and expanded its operations to the Gulf of Mexico. It was not until 1950, however, that oil and gas production from offshore platforms in State waters began in the Pacific region. It was also off southern California in the Santa Barbara area where the most serious offshore well blowout occurred in 1969. The impression that the Santa Barbara blowout made on the public continues to influence the Federal offshore leasing program, although a similar incident has not occurred again in the United States.

Four lease sale planning areas are located in the Pacific region: Southern California, Central California, Northern California, and Washington and

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[12] Minerals Managment Service, *Mid Atlantic Summary Report* (Washington, DC: U.S. Department of the Interior, 1983), p. 6.

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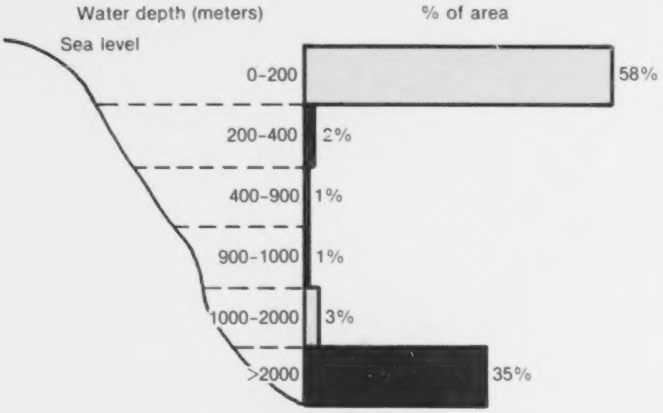
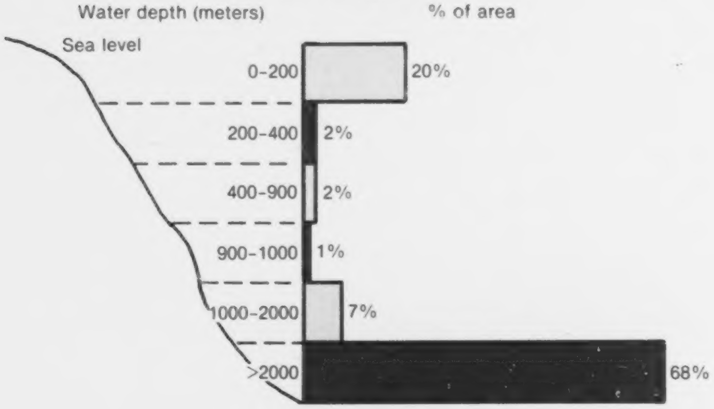
Figure 2-9.—Distribution of Atlantic Planning Areas by Water Depth

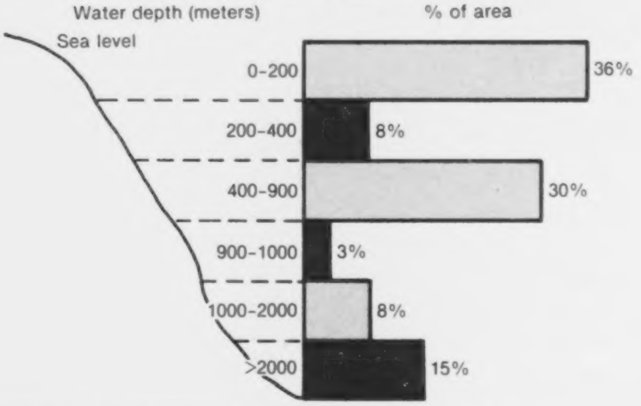
North Atlantic Planning Area



Mid-Atlantic Planning Area



South Atlantic Planning Area



SOURCE: Office of Technology Assessment.

Oregon. A large proportion (over 90 percent) of the area within the lease sale planning areas in the Pacific region is in water depths of more than 660 feet. Eleven sedimentary basins with potential for containing hydrocarbons are located in the Pacific region. The Santa Maria, Santa Barbara Channel, and Borderland basins in southern California are nearly geographically contiguous and offer the highest potential for petroleum development.

Oil and gas development in the Pacific region is concentrated in the Southern California area. Production from this area makes California the second ranking oil producing State and third ranking in natural gas production from the Federal Outer Continental Shelf. The most frequent oil and gas discoveries in the Pacific region have been mostly small fields of 100 million barrels or less. However, 80 percent of the combined reserves of oil and natural gas occur in larger fields ranging up to 400 million barrels.

Resource estimates. Total undiscovered economically recoverable crude oil resources are estimated to be about 4.6 billion barrels for all Pacific planning regions. Over half (2.4 billion barrels) is expected to occur in the Southern California Borderlands and Santa Barbara Channel lease planning areas. The largest proportion of crude oil is estimated to be located in the Central and Northern California lease planning area (1.9 billion barrels). Only 300 million barrels are estimated to exist in the Washington and Oregon area.

Total undiscovered economically recoverable natural gas resources (7.6 Tcf) are expected to be similarly distributed among the lease planning areas, with the most (2.5 Tcf) located in the Santa Barbara Channel, and a nearly like amount (2.3 Tcf) in the Central and Northern California lease planning areas. Approximately 60 percent of crude oil and natural gas within the Pacific region lease planning areas is expected to occur in water depths of 660 to 8,200 feet.

Physical and geological characteristics. The breadth of the Continental Shelf in the Pacific region ranges from about 25 to 30 miles off Point Conception in California to over 100 miles off San Diego. The Continental Slope plunges to depths between 1,300 and 9,750 feet at the base of the Slope. Depths in the Abyssal Plain beyond the Continental Rise within the EEZ may reach depths of about 14,675 feet off Washington and Oregon. Seventy six percent of the area in the Central and Northern lease planning areas and 48 percent of the area in the Southern California Borderland lease planning area are in water depths of 6,560 feet or more (see figure 2-10). Depths in the Santa Barbara Channel may reach 2,050 feet.[13]

Of the offshore areas in the Pacific region that have been explored for oil and gas, the Santa Barbara Channel and the Santa Maria basin have been most productive. In both instances, onshore oil and gas development adjacent to Point Conception and Point Arguello preceded petroleum discoveries offshore. The Point Arguello field within the Santa Maria basin is considered the largest field yet discovered in the U.S. Outer Continental Shelf. Its potential is rated at 300 to 500 million barrels.

The Pacific region lies along an axis of known seismic activity, and the potential for earthquakes is the major engineering factor affecting design of offshore platforms and underwater pipelines. Other hazards may exist in the form of subsidence, seafloor erosion, shallow gas deposits, and mass sediment movements.

Leasing and exploration. Oil and natural gas leasing in the Pacific region began in 1963 in the Central California lease planning area. A total of 14 oil and gas fields have been identified in the Pacific region. Two of these are natural gas fields; six are oil fields; and six are a combination of oil and gas. Oil has been discovered at wells in waters ranging from 1,097 to 1,544 feet deep off Point Arguello in southern California, but most of the oil discovered is heavy crude which may require development of special lift technologies to produce from those depths economically.[14] Exxon is planning to install a production platform (Hondo "B") in 1,200 feet of water in the Santa Ynez unit in 1987.

Development, production, and reserves. Crude oil production from the Pacific region peaked at 31 million barrels in 1971 and decreased to 10.2 million barrels in 1980. Pacific crude oil production

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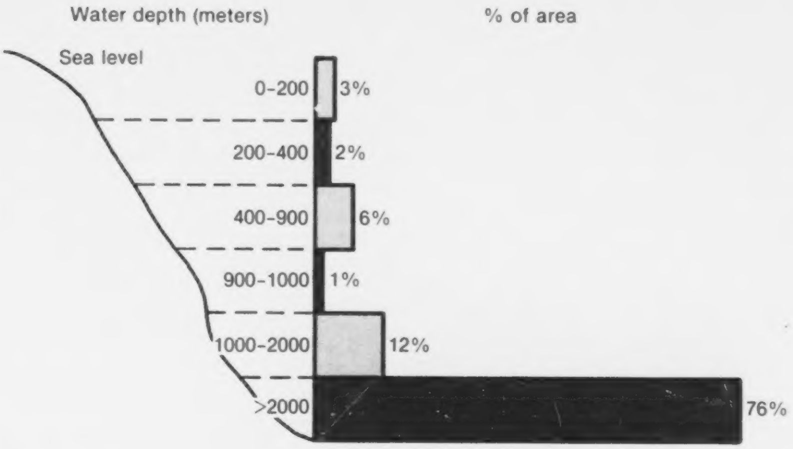
[13] Minerals Management Service, *Pacific Summary Report* (Washington, DC: U.S. Department of the Interior, 1983), p. 9.

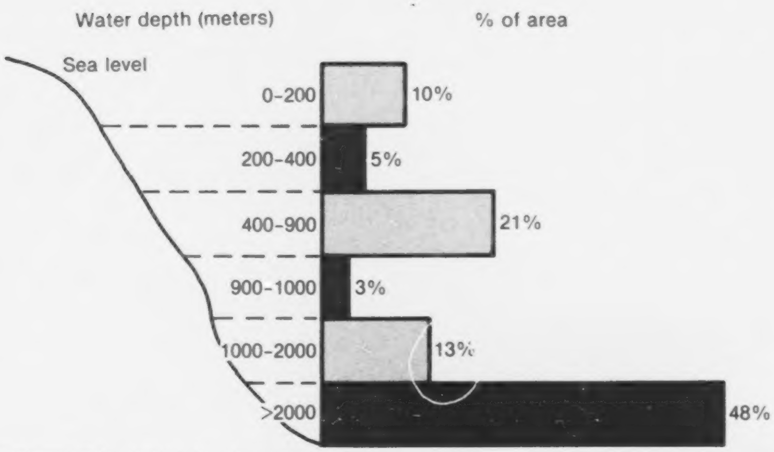
[14] *Oil and Gas Journal* "Offshore Southern California" (Jan. 9, 1984), p. 58.

Figure 2-10.—Distribution of Pacific Planning Areas by Water Depth

Central and Northern California Planning Areas



Southern California Planning Area



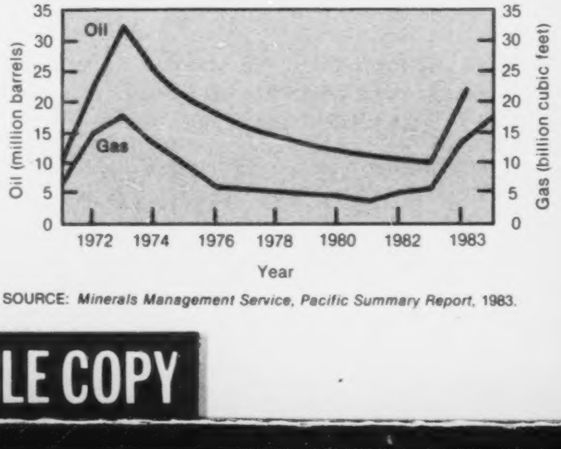
SOURCE: Office of Technology Assessment.

rose to over 28 million barrels in 1983 (see figure 2-11). Natural gas production followed a similar trend, peaking in 1971 at 15.7 billion cubic feet while decreasing to 2.9 billion cubic feet in 1979, and rebounding to nearly 18 billion cubic feet by 1983. Due to new discoveries, original reserve estimates for crude oil increased to 1.2 billion barrels in 1983 and natural gas to 2 Tcf.

Alaska

The Alaska region is remote, its operating conditions are hostile, exploration and production costs

Figure 2-11.—Trends in Pacific Region Oil and Gas Production



SOURCE: *Minerals Management Service, Pacific Summary Report, 1983.*

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are high, and its potential for oil and gas resources enormous. There is currently no oil or gas produced from Federal offshore lands in the Alaska region.

About 4 billion barrels of crude oil have been produced thus far from State offshore leases in the Cook Inlet since before 1954. In addition, onshore discoveries at the North Slope (Prudhoe Bay and Kuparuk fields) indicate that there may be 10 billion barrels of recoverable crude oil and 35 Tcf of natural gas directly adjacent to offshore areas in the Beaufort Sea. The occurrence of these petroleum resources on State lands which are adjacent to the Federal Outer Continental Shelf is considered to be an encouraging indication that vast petroleum resources may occur offshore.

The Alaska region consists of 15 lease sale planning areas: 1) Gulf of Alaska; 2) Kodiak; 3) Lower Cook Inlet-Shelikof Strait; 4) Shumagin; 5) North Aleutian Basin; 6) St. George Basin; 7) Navarin Basin; 8) St. Matthew Hall; 9) Norton Basin; 10) Bowers Basin; 11) Aleutian Basin; 12) Aleutian Arc; 13) Hope Basin; 14) Chukchi Sea; and 15) Beaufort Sea. Planning areas 1 through 4 are in the Gulf of Alaska subregion; 5 through 12 are in the Bering Sea subregion; and 13 through 15 are in the Arctic subregion. This assessment considers the Bering Sea subregion and the Arctic subregion—the offshore subregions north of the Aleutian Islands—as the "Arctic" for the purpose of assessing Arctic technology.

Resource estimates. The Beaufort Sea lease sale planning area is estimated to contain about 70 percent of the undiscovered economically recoverable crude oil and natural gas (8 billion barrels and 39 Tcf) expected to be found in the subregions north of the Aleutian Islands. The Chukchi Sea planning area, which lies to the west of the Beaufort Sea, is expected to contain about 4 billion barrels of crude oil and about 14 Tcf of natural gas. In total, over 80 percent of the crude oil and 76 perecent of the natural gas which may occur north of the Aleutian Islands in the Arctic and sub-Arctic lease planning areas of Alaska are expected to be in the Beaufort and Chukchi Seas.

Physical and geological characteristics. The Continental Shelf adjacent to Alaska represents about one-half the total U.S. Continental Shelf. Breadth of the Alaskan Continental Shelf varies significantly, from as narrow as 8 miles at the eastern end of the Gulf of Alaska to perhaps as wide as 500 miles or more in the northwest Chukchi Sea.

The Continental Slope adjacent to Alaska drops steeply to the abyssal depths. South of the Aleutian Islands, the Slope plunges between 16,400 and 19,680 feet in the Aleutian Trench. Depths in the Abyssal Plain of the Gulf of Alaska range to about 13,120 feet. Maximum depths in the Navarin Basin lie between 11,480 and 12,790 feet, while the maximum depths in the Arctic Ocean within the U.S. EEZ are about 7,870 feet.

Over 80 percent of the area within the Navarin Basin lease sale planning area is in water depths of about 660 feet or less while about 83 percent of the area in the Beaufort Sea planning area is in waters 66 feet or less (see figure 2-12).

The southern Alaskan lease sale planning areas along the Alaskan peninsula and the Aleutian Islands are in seismically active areas where earthquakes and possible tsunamis must be considered in designing oil and gas exploration and production systems. Sediment instability, which may result in sediment slides and slumping in areas seaward of about 160 to 213 feet, may occur in the Alaska region. In the Bering Sea, faulting, shallow gas-charged sediments, and sediment erosion and transport are geological factors that must be considered in offshore engineering design.[15]

Leasing and exploration. The first oil and gas lease sale in Federal waters off Alaska was in the Gulf of Alaska in 1976. Since that time, about 3.8 million acres have been leased in Alaskan waters. This represents more leased acreage than any other offshore region, with the exception of the Gulf of Mexico.

Exploration efforts in the Yakataga area of the Gulf of Alaska, which began in 1976, resulted in 11 dry holes. Since that time, the industry has shown less interest in exploration in that area. Eight exploratory wells drilled in the Lower Cook Inlet planning area between 1978 and 1980 also yielded dry holes, and no further exploration has taken place.

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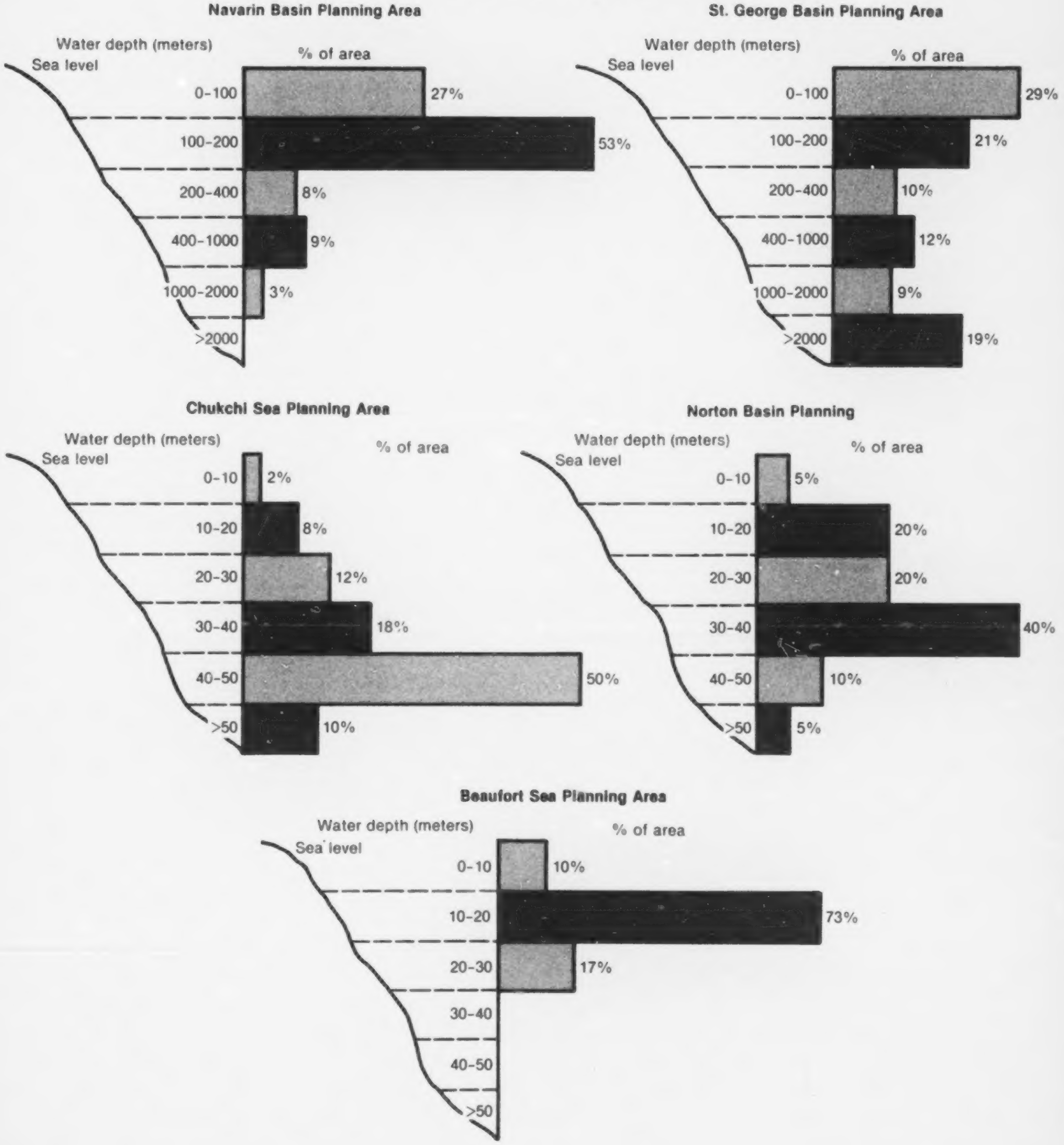
[15] Minerals Management Service, *Bering Sea Summary Report* (Washington, DC: U.S. Department of the Interior, 1983), p. 33.

Figure 2-12.—Distribution of Alaskan Planning Areas by Water Depth


Navarin Basin Planning Area

St. George Basin Planning Area

Chukchi Sea Planning Area

Norton Basin Planning

Beaufort Sea Planning Area

SOURCE: Office of Technology Assessment.

In the Bering Sea subregion, six deep stratigraphic test wells have been drilled. Exploration has recently commenced in the St. George Basin and Norton Sound planning areas. Planning for exploration in the Navarin Basin lease planning area is currently underway.

Exploration in the Arctic subregion has shown mixed results. The disappointment of the failure of Sohio Alaska Petroleum Company's Mukluk exploration well, which reportedly cost $140 million, is offset by the Shell commercial discovery at Seal Island in the Beaufort Sea planning area (joint Federal-State lease) near the Prudhoe Bay onshore field. The next exploration well in the Beaufort Sea will be at Exxon's Antares site about 45 miles northwest of the Mukluk site.

Chapter 3

Technologies for Arctic and Deepwater Areas

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Chapter 3

Technologies for Arctic and Deepwater Areas

OVERVIEW

Technology employed by the offshore petroleum industry has changed dramatically over the past 20 years, allowing the international petroleum industry to explore and produce in environments that were considered almost prohibitive two decades ago. This technology development which has revolutionized the offshore petroleum business is a result of adaption, innovation, and integration.

Industry began its move to deep and hostile environments by first applying land-based techniques to the marine environment in discrete incremental steps. Progressively, industry resolved the problems encountered offshore by adapting existing systems or techniques or by designing new ones as needed. Experience in the Gulf of Mexico, where exploration and production have moved from land to shallow water to deep water, demonstrates this progression of technology adaptation.

New technologies also have resulted when a major challenge or opportunity called for innovative approaches. For example, dynamic positioning was a major innovation during the government's 1960 Mohole Project; acoustic-guided hole reentry was a major innovation of the government's Deepsea Drilling Project of the 1970s; and innovations in diving and underwater vehicles grew out of Navy programs in the 1960s and 1970s. In private industry, Deep Oil Technology's tension leg platform, IMODCO's single point mooring system, Shell's first semi-submersible rig in the 1960s, Exxon's deepwater guyed tower, and Conoco's tension leg platform in the 1980s are also examples of major innovations.[1]

Finally, the integration of marine and ocean engineering with petroleum engineering and the business of oil drilling and production has brought varied experience to bear on design, construction, safety and reliability. The basic principles of each field have been used effectively to design new systems to develop and produce petroleum resources in the hostile marine environment (see figure 3-1).

Today more than one-quarter of world oil production is from offshore regions (see table 3-1). That portion has been growing at a rate of nearly 10 percent per year for the past decade, and major exploration activities continue off the East, West, and Gulf Coasts of the United States; in offshore Alaska; in the Asia-Pacific, especially the China Sea; off Latin America, especially Brazil; in the northern North Sea; and off Canada. Several of these regions could be categorized as hostile environments because of storms, severe waves and currents, deep water, or Arctic or sub-arctic conditions.

For example, exploration has been underway for several years under the severe ice conditions of the Beaufort Sea off the United States and Canada; in iceberg conditions along Greenland and eastern Canada; and under severe wind, wave, current, and deepwater conditions along the eastern Canadian and U.S. coasts, in the North Sea, and off southern Australia. Outside of the United States, the major offshore production experience in very hostile environments has been in the North Sea. The major offshore exploration experience in hostile waters (without production to date) has been off the coast of Canada.

The Canadian Beaufort Sea exploration activities have been in the forefront of operations in severe ice and cold conditions. Eastern Canada and U.S. Atlantic Coast offshore exploratory drilling have set rough water records. Exploratory activities in the Mediterranean and off the U.S. Atlantic coast have set water depth records (see figure 3-2).

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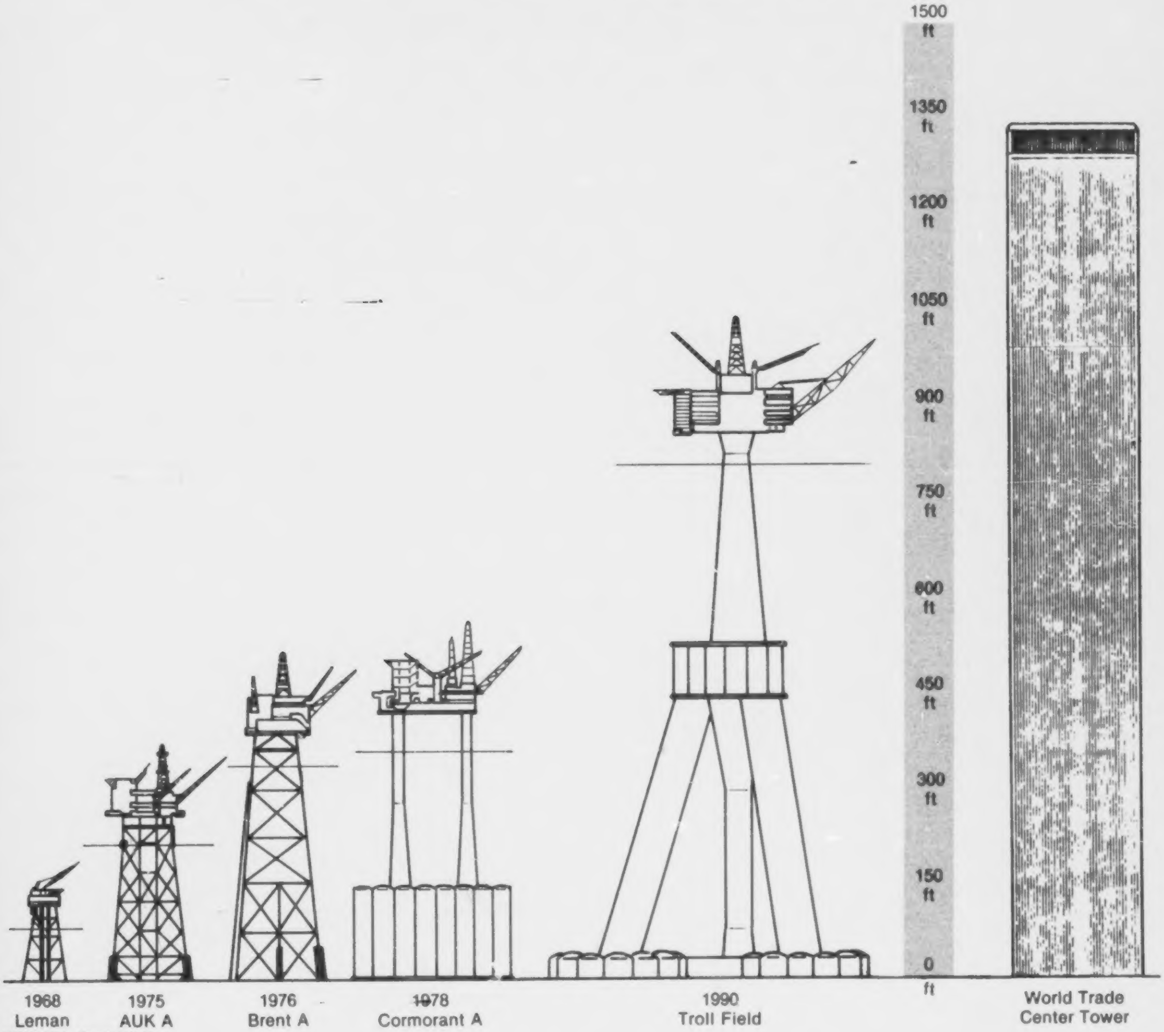
[1] U.S. Congress, Office of Technology Assessment, *Ocean Margin Drilling—A Technical Memorandum* (May 1980); and *Proceedings of the Offshore Technology Conference* (May 1984).

Figure 3-1.—Progression of Production Platforms for the North Sea


1500 ft
1350 ft
1200 ft
1050 ft
900 ft
750 ft
600 ft
450 ft
300 ft
150 ft
0 ft
1968 Leman
1975 AUK A
1976 Brent A
1978 Cormorant A
1990 Troll Field
World Trade Center Tower

SOURCE: Shell Oil Co.

In each of these situations, new technologies were necessary for effective operations in very harsh environments. These technologies ranged from deepwater risers to concrete gravity structures to deepwater pipelines. Some examples of production platform technologies for hostile environments are shown in figure 3-3.

Offshore petroleum activities are commonly divided into three phases: 1) exploration; 2) development; and 3) production. Exploration includes some pre-lease activities such as geological and geophysical surveys as well as the exploratory drilling that occurs (in the United States) after a lease sale. Development begins after an oil or gas discovery is determined economic and includes the delineation of the reservoir as well as the drilling of production wells and the design and construction of all facilities for producing a field. Production begins with the flow of oil or gas to a market and concludes when a field is depleted. In offshore frontier regions, it is not unreasonable to expect exploration to con-

Table 3-1.—World Offshore Oil Production

Region or area	Oil production (million bbl/day) 1983 (actual)	1984 (projected)
Middle East	3.74	3.88
Latin America/Caribbean[a]	3.24	3.36
North Sea	2.88	3.05
United States (GOM + Calif.)	1.68	1.78
Southeast Asia and Oceania	1.53	1.56
West Africa	0.80	0.80
U.S.S.R.	0.18	0.17
Mediterranean	0.14	0.15
Total	14.19	14.75
Percent of onshore + offshore	26.6%	27.7%

[a] Latin America/Caribbean includes Mexico, Venezuela, Trinidad, Brazil, and Argentina as key producers.

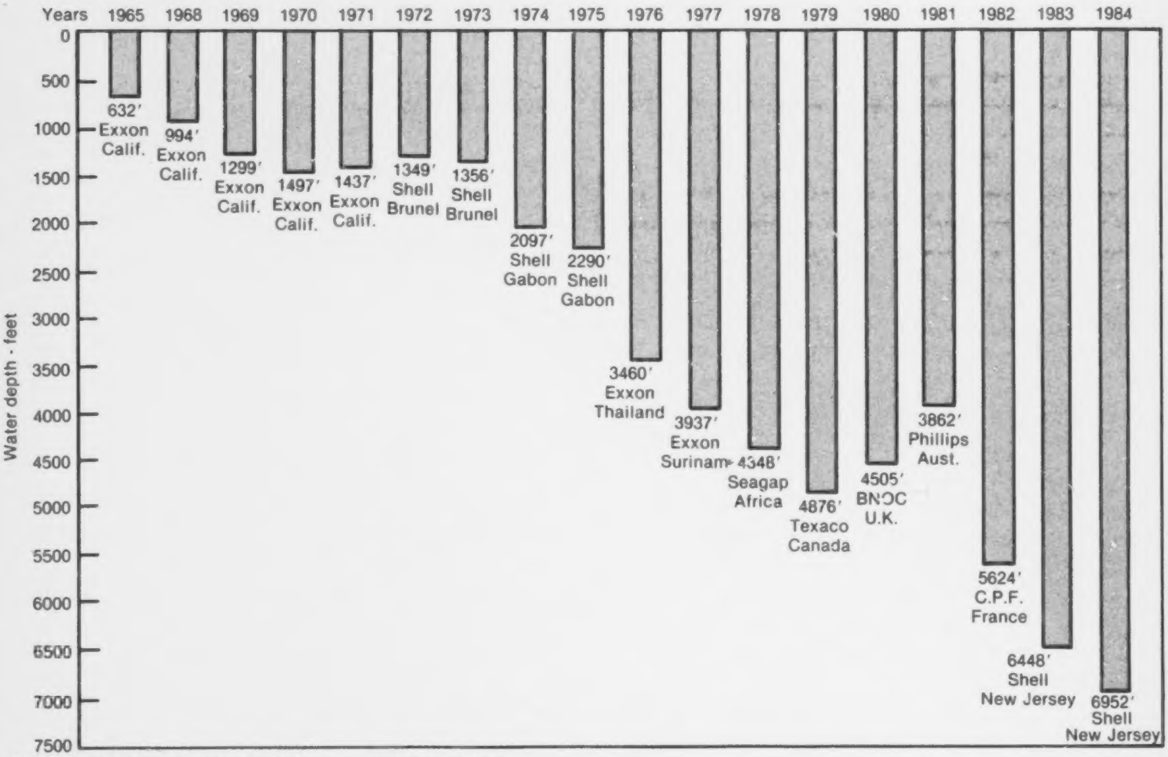
SOURCE: *Offshore Magazine*, May 1984.

tinue for 10 years or more, development work to continue for 10 years, and production to continue 20 or more years. One would expect, therefore, that if discoveries are made in U.S. deepwater or Arctic regions, the major activities would continue well into the next century.

The three phases described above do not start and end abruptly; they usually overlap to a considerable extent. Exploration for smaller fields may continue long after major fields in a region are in full production. The development of a field may proceed in stages with the addition of gas injection, water injection, or other systems to enhance recovery as the field is being produced. And production usually starts before a field is completely developed, especially if it is very large and complex.

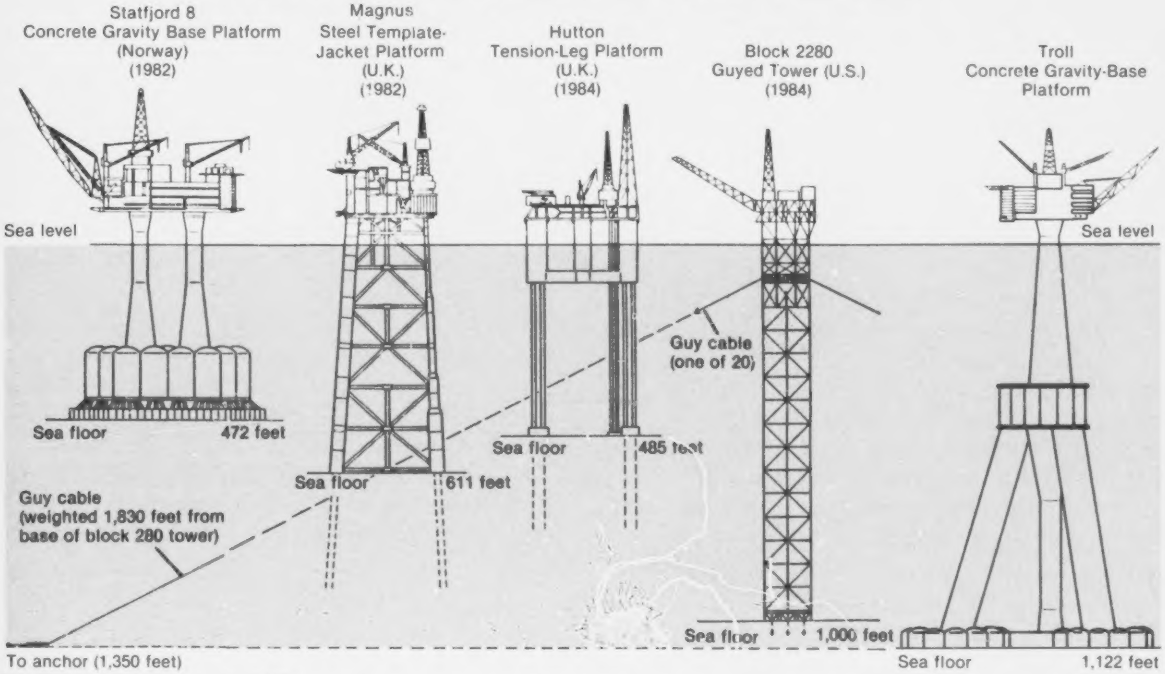
Since the focus of this assessment is the deepwater and Arctic frontiers where no production has begun, the technologies discussed fall into two categories: 1) exploration systems which *have* been used for several years; and 2) production systems which *have not* been used but exist in designs, plans, and sometimes prototype test equipment.

Figure 3-2.—Water Depth Records for Drilling Operations



SOURCE. Proceedings, DOI EEZ Symposium, Nov. 1983, updated 1984.

Figure 3-3.—Production Platform Technologies for Frontier Areas


Statfjord 8
Concrete Gravity Base Platform
(Norway)
(1982)
Magnus
Steel Template-
Jacket Platform
(U.K.)
(1982)
Hutton
Tension-Leg Platform
(U.K.)
(1984)
Block 2280
Guyed Tower (U.S.)
(1984)
Troll
Concrete Gravity-Base
Platform
Sea level
Sea level
Sea floor
472 feet
Sea floor
611 feet
Sea floor
485 feet
Guy cable
(one of 20)
Guy cable
(weighted 1,830 feet from
base of block 280 tower)
Sea floor
1,000 feet
To anchor (1,350 feet)
Sea floor
1,122 feet

SOURCE: *Scientific American*, April 1982.

However, even though these production systems have not been used in the regions under consideration, many individual components are similar to those already in service in other regions. A total technical system will, therefore, be built from a combination of tried and tested subsystems and components newly designed to meet added demands.

The types of drilling, production, and transportation systems for each frontier area must be selected to fit the prevailing conditions of the working environment (e.g., ice, deepwater, or storms), prospective field characteristics, and the proximity to other developments. For example, a discovery in the Alaskan Beaufort Sea near Prudhoe Bay probably would be developed using much of the same technology as that used on the nearby land sites. Because of the site-specific nature of most offshore oil and gas technology and also because of the great variety of technology possibilities available, discussions in this chapter are based on specific systems which may be used in the Arctic and deepwater scenarios developed by OTA.

THE ARCTIC FRONTIERS

Overview

Commercial oil activities in the Arctic date back to a State lease sale in December 1964 onshore in the Prudhoe Bay area. Production from the onshore North Slope fields began in 1977 and in 1984 was 1.6 million barrels per day.

Offshore exploration in the Arctic region began in the mid-1970s in State waters of the Beaufort Sea. Prior to this, the only significant activity in the Alaskan offshore was outside the Arctic in Cook Inlet and the Gulf of Alaska. Oil production from offshore platforms in Cook Inlet began in 1964. Exploratory drilling in the Gulf of Alaska in the late

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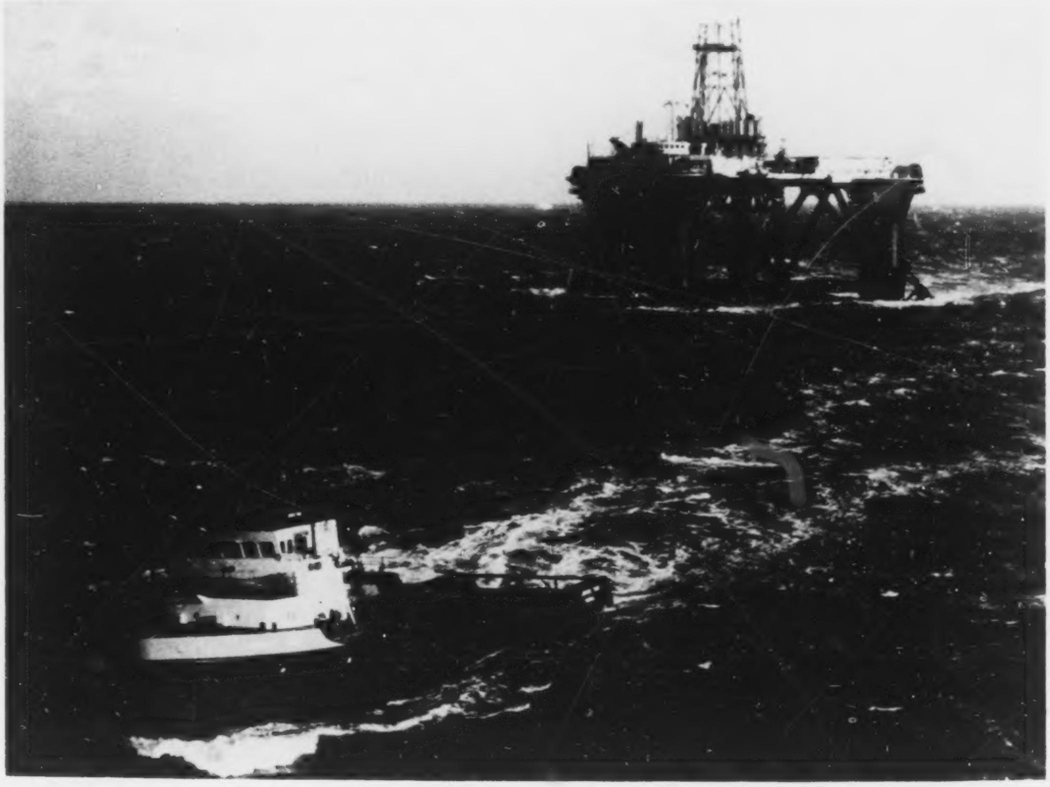
1970s produced no discoveries of economic significance.

The first exploratory wells in the waters north of Alaska were drilled from natural islands in Steffenson Sound (e.g., Gull Island in 1974 and Niakuk Island) followed in 1977 by drilling from a built-up sea ice platform in Harrison Bay. Since then, many exploratory holes have been drilled from manmade gravel islands or off the barrier islands along the Beaufort Sea coast. Exploratory drilling in the Bering Sea region began in 1982. Drilling in the Bering Sea has been conducted in the summer ice-free season with technologies that have been used in temperate offshore regions. A concrete island drilling structure is now being used for exploratory drilling north of Cape Halkett in Harrison Bay.

The first Federal offshore activity in Arctic Alaska was the joint Federal/State Beaufort Sea lease sale in December 1979. Since then, the pace of offshore activity and the rate of technological advancement have increased significantly. The first wholly Federal offshore lease sale took place in October 1982 in the Beaufort Sea. To date, the Federal Government has conducted four more sales in Arctic Alaska, three in the Bering Sea—Norton Sound, the St. George Basin, and the Navarin Basin—and a second in the Beaufort Sea (Diapir Field).

In May 1982, Sohio and Exxon jointly announced tentative plans to develop the 350-million-barrel Endicott field (also known as the Sag River/Duck Island field) portion of the joint Federal/State lease sale area. By February 1985, Sohio had received all necessary permits and launched work leading to the first commercial oil production in U.S. Arctic waters. In November 1983, Sohio began drilling the first exploratory hole in the



Mobile offshore exploratory drilling unit, like those used in offshore Arctic areas, is towed to new drilling site

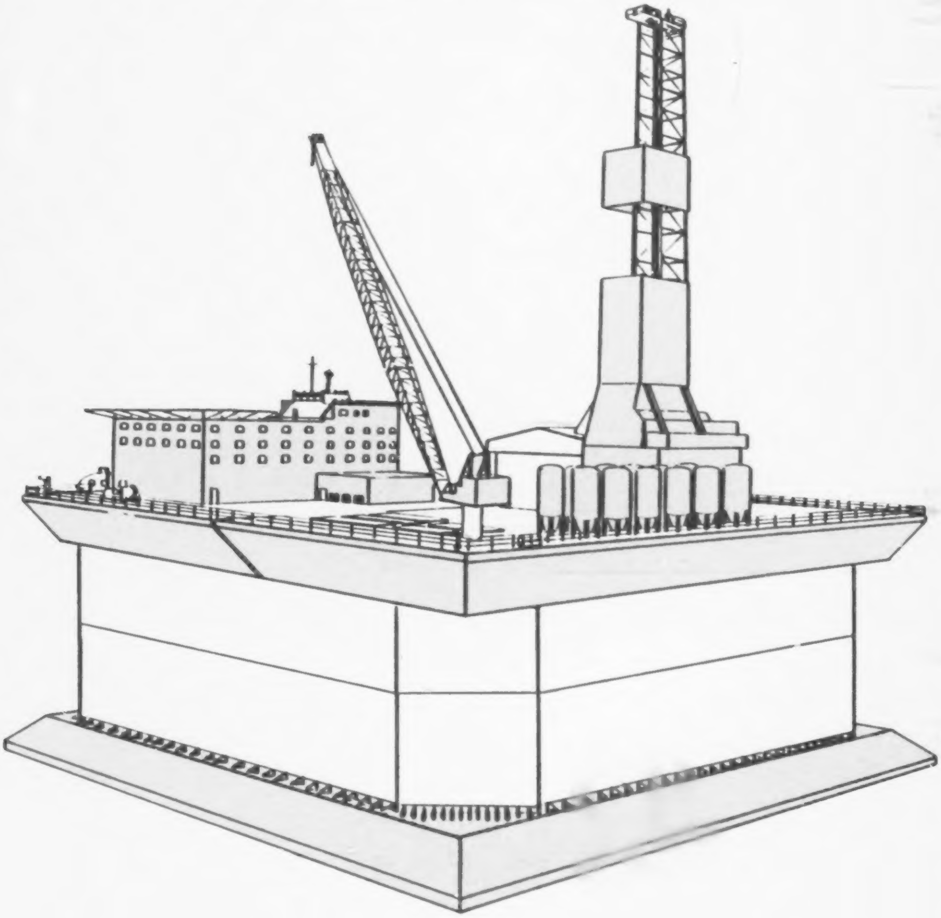
Mukluk area of Diapir Field. However, Mukluk was determined nonproductive. In May 1984, Shell announced a large oil discovery from Seal Island in a joint Federal/State sale area. In both cases, drilling was from manmade gravel islands. Exxon drilled the first exploratory well from an Arctic mobile offshore drilling unit (MODU) in late 1984 northwest of Mukluk. This used a concrete island drilling system known as "Super CIDS," which can be moved to another location if desired after drilling is completed at the site[2] (see figure 3-4).

Offshore petroleum development in the Arctic will be a major technological challenge. The environment is severe and will dictate a rigorous approach to design and construction of all primary and support systems. While considerable data have been collected, additional engineering data will need to be compiled and verified. The cold temperatures, ice, harsh weather, and remoteness of many Arctic regions will force the use of costly equipment to achieve the required reliability. Some of the exploration and development milestones in offshore Arctic technology are shown in figure 3-5.

Field Characteristics

The field characteristics of the six key Arctic planning areas are given below.

Figure 3-4.—Mobile Offshore Drilling Unit



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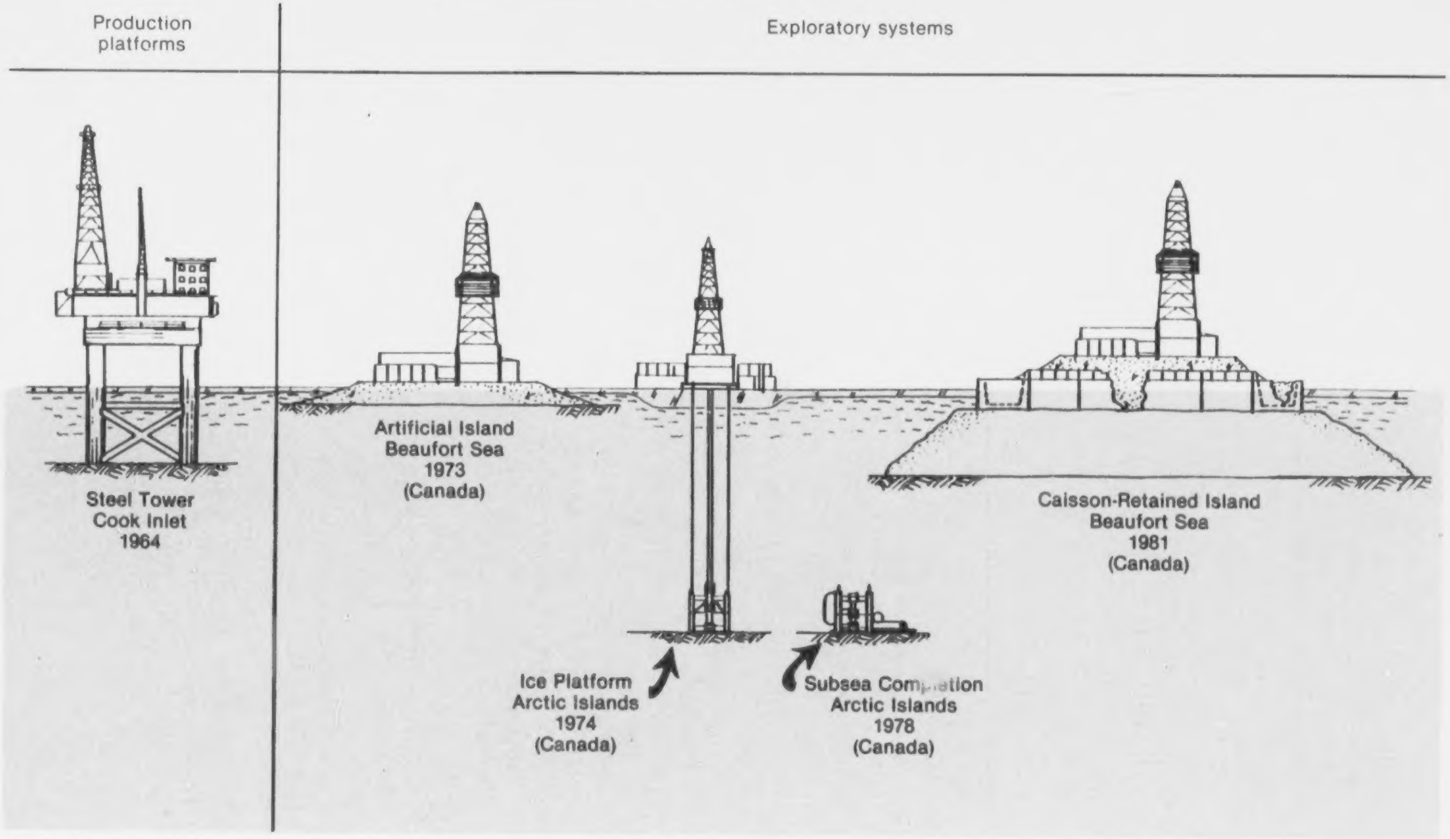
[2] "Drillers Seek Alaska Supergiant," *Offshore* (January 1984).

Figure 3-5.—Arctic Exploration and Development Milestones


Production platforms
Exploratory systems
Steel Tower
Cook Inlet
1964
Artificial Island
Beaufort Sea
1973
(Canada)
Ice Platform
Arctic Islands
1974
(Canada)
Subsea Completion
Arctic Islands
1978
(Canada)
Caisson-Retained Island
Beaufort Sea
1981
(Canada)

SOURCE: Proceedings of DOI EEZ Symposium, November 1983.

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Beaufort Sea

There are four main types of geologic settings in the Beaufort Sea which potentially contain oil. They are listed below in the order of probability. Only the first two are candidates for exploratory drilling at this time.

Ellesmerian Sequence.—This prospective sequence extends from Smith Bay on the west to Mikkelsen Bay on the east, becomes thinner as it extends north from land, and ends at approximately 71°13′ N latitude. It includes the Lease Sale 71 area which incorporates Harrison Bay. Since the Ellesmerian Sequence includes the Prudhoe Bay fields, oil similar to the Prudhoe type may be found in the Lease Sale 71 area. This means an oil with an average gravity of about 28° and with a low sulphur content; therefore, a good quality oil. The area of Ellesmerian potential has gentle structural folds which means that it could contain several very large accumulations of oil instead of numerous small ones.

Tertiary Structures.—These structures are east of the Ellesmerian Sequence and extend from Camden Bay to the Canadian border. This means that they are east of the Lease Sale 71 area but within Lease Sale 87 which occurred in August 1984. The seaward extent of these structures is approximately to 70°35′ N latitude. These structures contain more convolutions and peaks than the Ellesmerian Sequence which means that the area, if productive, may contain more smaller oil fields. These structures also are located in regions of more severe ice conditions.

Growth Fault Structures.—These structures relate to the growth faults and roll-over anticlines. They overlap the Ellesmerian Sequence in the northeasterly portion of Lease Sale 71 and then extend seaward. Little is known about possible oil fields in these structures.

Cretaceous Tertiary Clays.—These formations are expected to contain scattered smaller fields and are less promising than the Growth Fault Structures for finding oil. They are located in the central and western Beaufort shelf regions.

Chukchi Sea

The Chukchi Sea appears to contain three areas with favorable hydrocarbon potential. Most favorable is the Central Chukchi Shelf, which is northwest of Alaska—particularly the area along the northern coast. It contains a very thick sedimentary section and many anticlines. It is the offshore extension of the Colville Trough—the province of North Slope oil and gas. Reservoir rocks are potentially the same as those in the Sadlerochit Group and the Kuparuk River sandstones.

The southern part of the Central Chukchi Shelf and the Northern Chukchi Shelf are the other two potential areas. The southern part is an overthrust zone similar to the foothills province of the Brooks Range. The North Chukchi Shelf contains great thicknesses of (inferred) Cretaceous and Tertiary rocks containing shale diapirs.[3]

Reservoirs in this area could be located from 5,000 to 25,000 feet below the seafloor with an average well depth of 10,000 feet. It is geologically possible that a giant oil field in excess of 1 billion barrels in size could exist in this area.

Norton Basin

Due to the limited geologic information available on Norton Basin, reservoir and production assumptions have been made based on similar geologic basins for which more data were available; specifically, these are the Anadyr Basin of northeast Siberia and Cook Inlet in Alaska. The assumptions are that the average reservoir depths range from 2,500 to 7,500 feet, that the recoverable reserves per acre could range from 20,000 to 60,000 barrels, and that the initial well productivity could range from 1,000 to 5,000 barrels per day. Field sizes could be in the range of 100 million barrels or more.[4]

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[3] Dames & Moore, "Chukchi Sea Petroleum Technology Assessment," report prepared for the Minerals Management Service (December 1982).

[4] Dames & Moore, "Norton Basin OCS Lease Sale No. 47 Petroleum Development Scenarios," report prepared for Bureau of Land Management (August 1980).

St. George Basin

The St. George Basin is floored and flanked by folded Mesozoic rocks that extend from southern Alaska to eastern Siberia. Geophysical data and the extrapolation of onshore information to offshore areas suggest that suitable source beds, reservoir rocks and traps all exist within the St. George Basin. Very little data are available with which to speculate on field characteristics.[5]

North Aleutian Basin

The North Aleutian Basin is a large sediment-filled structural depression that underlies portions of the Alaska Peninsula and the Bering Sea. Within the basin, Mesozoic basement rocks are overlain primarily by Cenozoic sedimentary rocks. The information garnered from nine wells drilled on the Alaska Peninsula adjacent to the axis of the basin is encouraging for the prospect of discovering hydrocarbons. The majority of potential oil and gas traps within the basin are believed to be associated with anticlinal structures.

Navarin Basin

Navarin Basin includes three thick sedimentary sub-basins. There are also several large anticlinal structures, smaller folds, diapirs, and stratigraphic traps. There is potential for giant oil fields in excess of 100 million barrels. Due to the great thicknesses of the sedimentary deposit, reservoirs could occur at depths below the seafloor, ranging from shallow to very deep. Reservoir depths are estimated between 6,500 and 11,500 feet in the northern portion of the Basin and between 3,300 and 13,000 feet in the southern portion.[6]

Environmental Conditions

Petroleum resource development in the offshore Arctic is conducted under unique cold-region, high-latitude environmental conditions. Among the conditions are: ice and its many impacts; ocean floor geotechnical properties; seasonal fog; and periods of up to 24 hours of light or darkness. Offshore conditions are severe and the locations are remote and difficult to support. In order to operate successfully and to minimize the risk to personnel, facilities, and the environment, these environmental conditions, and their impact on materials, logistics, operations, and human factors, must be taken into consideration. Because of these conditions, time relationships become critical—not only for exploration but also for data gathering, logistics, production, and virtually every other operational consideration. Figure 3-6 illustrates environmental load comparisons for different structures and regions to show the significance of wave and ice loads.

The northern Alaska environment can be thought of as a frigid desert with some precipitation, low temperature, high wind, and periods of extended fog. The climate in the areas north of the Bering Strait is very harsh. Based on data from the Climatic Atlas, early air temperatures vary from a low of approximately -47° F to a high of approximately 57° F. Temperatures even lower than -50° F occur at Pt. Barrow. The areas south of the Bering Strait have a less severe climate. In the Norton Basin, the extreme low temperature is -36° F; in the Navarin it is -11° F; and in the St. George it is 3° F. The maximum 100-year wind north of the Bering Strait is 97 knots. This increases south of the Bering Strait to a maximum of 108 knots in the Navarin Basin.[7]

Photo credit: Shell Oil

Offshore platforms in frontier areas must withstand tremendous environmental forces

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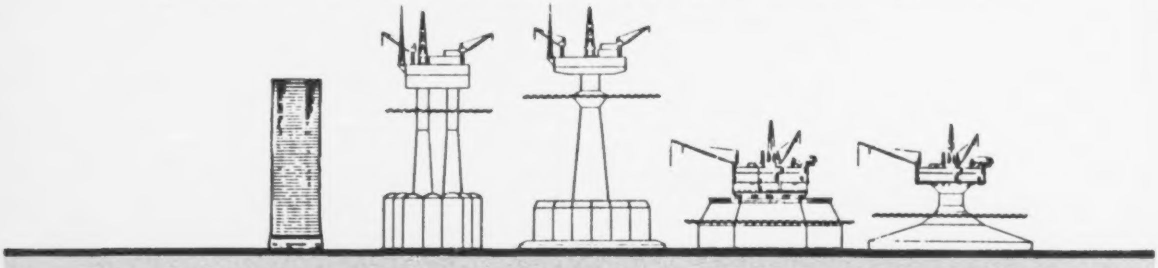
[5] Dames & Moore, "St. George Basin Petroleum Technology Assessment," report prepared for Bureau of Land Management (August 1980).

[6] Dames & Moore, "Navarin Basin Petroleum Technology Assessment," reported prepared for Bureau of Land Management (June 1982).

[7] W. A. Brower and H. W. Serby, *Climatic Atlas of the Outer Continental Shelf Waters and Coastal Regions of Alaska* (1977).

Figure 3-6.—Environmental Load Comparison for Representative Gravity Structures



	50 story building	North Sea condeep	Bering Sea monotower	Norton Sound concrete island	Beaufort cone
Water depth (ft)	0	300-500	300-600	45-90	50-200
			Typical horizontal loads (10^6 lbs)		
• Wind	1-5	1	1	1	1
• Earthquake	1-5	30	70	100	50
• Waves	—	100	70	100	30
• Ice	—	—	10	100	100-200

SOURCE: Hans O. Jahns, "Offshore Outlook-Technological Trends: American Arctic," Offshore Mechanics and Arctic Engineering Symposium (Dallas, Texas, February 1985).

The northern Alaska OCS is relatively stable seismically. A review of observations made over the past 20 years in the Beaufort Sea region from the coast out to about 100 miles offshore shows four seismic events, each equal or less than 4.5 on the Richter Scale. Significant seismic activity, however, is located along the Mid-Arctic Ridge in the Eurasian Basin of the Arctic Ocean and along the Aleutian Chain off southwest Alaska. Oil exploration and development operations in the southern Bering Sea must take into account seismic activity along the Aleutian Chain.

There is some controversy about the completeness and accuracy of existing data on environmental conditions in the offshore regions. Some believe the Climatic Atlas data may overestimate oceanographic conditions, while others believe that given extremes may be even greater than existing data. The American Petroleum Institute is sponsoring work to produce a recommended-practice document that will include ranges of wind, wave, and current values based on more accurate and recent measurements. The revised values being considered are shown in table 3-2. Based on these estimates, maximum wave heights could vary from about 40 feet in the Beaufort Sea up to 90 feet in the St. George and Navarin Basins (corresponding to the 100-year storm).

Table 3-2.—Proposed Arctic Environmental Design Conditions

Area	Maximum 100-year wind[a] (knots)	Significant 100-year wave height (feet)	Surface currents velocity (knots)
Beaufort Sea	60 to 80	20 to 30	1 to 6
Chukchi Sea	60 to 80	20 to 30	1 to 5
Norton Basin	55 to 85 (90)[b]	30 to 40[c]	1 to 4
St. George Basin	55 to 85 (88)[b]	40 to 50	2 to 4
Navarin Basin	50 to 80 (90)[b]	40 to 50	1 to 3

[a] These are 1 hour averages to combine with extreme waves. Totally wave independent values would be somewhat higher, but structural loading calculations generally consider joint effects of winds and waves.

[b] These are wave independent numbers.

[c] Values for water depths greater than 75 ft. For shallower water, wave heights are limited by breaking waves.

SOURCE: Exxon, 1984.

Most experts agree that for design purposes sea ice is the most significant environmental parameter in the Arctic offshore. The duration of ice cover can vary from 10 months or more duration for the Beaufort Sea and Chukchi Sea to 1 month or less in the southwest Alaska St. George Basin. In some years there is no ice in the St. George Basin. Since the Navarin Basin is quite large, ice conditions vary considerably from north to south. Ice thicknesses

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vary correspondingly. The Climatic Atlas data show single-year, plane ice thicknesses of up to 7 feet in Diapir and 2.5 feet in St. George.

Additional offshore Arctic environmental design conditions for five of the lease sale planning areas are shown in table 3-3. These data are derived from the Climatic Atlas and are considered representative although site-to-site variations may be substantial.

Ice

Ice problems largely dictate criteria for Arctic design and operations. Sea ice creates the major difficulties. However, other ice, such as ice islands, floebergs, and structural icing on platforms, ships, and helicopters also present problems. The characteristics of sea ice, pressure ridges, and ice movement are the main concern in the design of Arctic structures. Some ice islands are so large that major damage could result from a collision between them and an offshore structure. Fortunately, because of the scarcity of ice islands, the probability of such an occurrence is relatively low. More likely events are the collision of pressure ridges with certain types of platforms and the ride-up of sea ice onto gravel islands. Ice ride-up can occur when the wind or current forces acting on ice cover force the ice against the land or an offshore structure. If the forces are large enough the ice can be driven up onto the structure or inland for distances of 300 feet or more. Pressure ridge keel seabottom gouging depths are a design concern which influences the depth of burial of offshore pipelines and seafloor well heads.

Sea ice is the single most important environmental factor affecting operations in the Arctic. Ice affects all aspects of oil and gas activities—from the design and construction of facilities which can withstand ice conditions to planning for transportation or possible rescues.

There is no simple description for Arctic sea ice. Even the initial formation of crystals varies widely depending on the roughness of the sea. With calmer seas, the crystals are larger and more platelike. In rougher waters the crystals are smaller and more granular. Once crystals have formed and have developed a thin skin on the surface of the water, the growth of the ice takes place on the underside. Salt brine pockets develop between the lattice networks of relatively pure water crystals. Over a period of time these pockets drain. The process of drainage is complicated by the percolation of summer melt through the ice. Multi-year ice becomes nearly drained of the salt and takes on a bluish hue.

The strength of ice is dependent on many factors including brine content, crystal orientation, temperature, age, and ice type. Recent data show that multi-year ice strengths may fall within the upper range of first-year ice strengths and in some cases (granular ice) may not be as strong. However, statistically and probabilistically, multi-year

Table 3-3.—Arctic Environmental Design Conditions

Area	Temperature		Ice duration (months)	Ice thickness (feet)	Minimum daylight hours		Water depth (feet)	Distance from shore (miles)
	Wind chill (°F)	Min (°F)			(hours)	(month)		
Beaufort Sea	-90	-47	10	7	0	Jan. Dec.	33-200	3-40
Chukchi Sea	-85	-44	8-10	5-7	0	Jan. Dec.	30-150	3-45
Norton Basin	-72	-36	8	3.5	4.5	Dec.	30-85	9-62
St. George Basin	-35	3	1-1/2	2.5	7.0	Dec.	344-472	60-180
Navarin Basin	-54	-11	5	3.0	6.0	Dec.	240-450	400-700

NOTES:
1. Water depth values represent approximately 95 percent of the water depths — the extreme high and low depths were excluded.
2. Distance from shore for Navarin Basin is from Dutch Harbor in the Aleutians, all others are from the mainland.
3. Daylight hours shown are for time the sun is above the horizon. In addition, twilight hours are often added to these numbers, especially for the far north regions.
4. The ice thickness values apply to annual sheet ice.

SOURCE: W. A. Brower and H. W. Serby, *Climatic Atlas of the Outer Continental Shelf Waters and Coastal Regions of Alaska*, 1977.

ice is stronger than first-year ice. While first year ice may grow to 6 to 7 feet thick, multi-year ice may grow to about 12 to 16 feet thick. In shallow water, shore-fast ice areas, first-year ice as thick as seven feet has been observed. The ultimate thickness depends on many factors including the radiant solar energy absorbed, long wave period energy radiated from ice into space, temperature of the air above the ice, and the thermal insulation, or inversely, the heat conductivity of the layer of ice and any snow cover. An equilibrium occurs, and the ice thickness is stable when the amount of heat absorbed by the ice from the water is in balance with the heat absorbed from the ice by the air. However, a large amount of thickness "growth" can be attributed to pressure ridge building and rafting.[8]

Sea ice modification results from interactions with the wind and ocean currents. The build-up of forces within the ice floes can cause the fracturing of the plates and a restructuring of the ice. The ice may be split apart resulting in long openings, perhaps tens or hundreds of kilometers long. Should these be sufficiently wide for the passage of a ship or whales they become "leads." Many are very narrow, however, and immediately refreeze or close again as the ice continues to move.

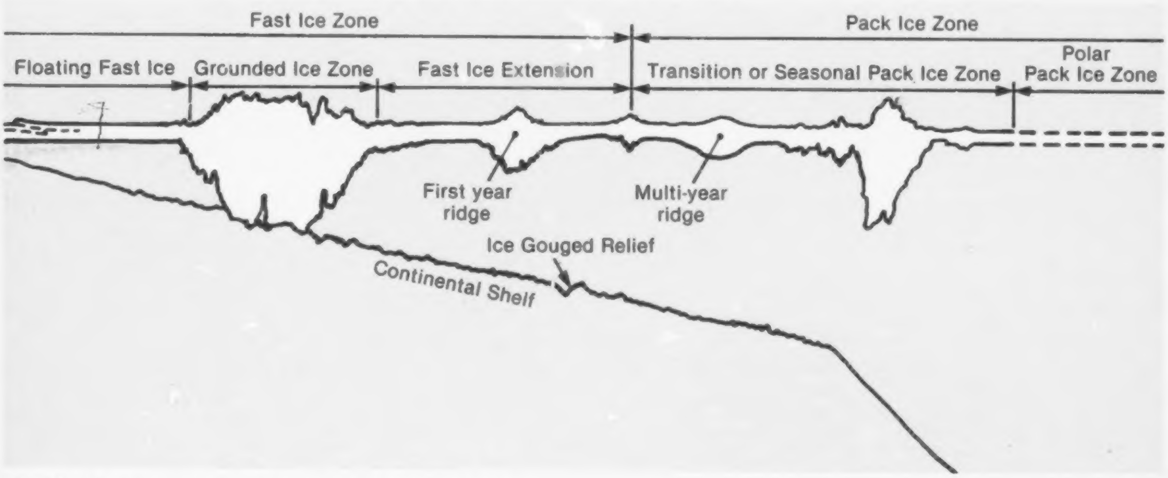
Having once parted, the two walls may be driven together causing upheavals and downward thrusts of the sheets and the formation of pressure ridges. Pressure buildup within ice floes may also cause deformation resulting in pressure ridges and rafting. The surface height of the ridge sails formed may be as much as 25 feet, while the depth of the ridge keels thus formed may be as great as 100 feet.

The restructuring of the broken ice results in various orientations of blocks. Any preferred orientation of ice crystals within the ice structure prior to ridging becomes randomized as broken blocks are tilted and tumbled. Interstices between the submerged blocks fill with sea water. The heat-sink capacity of the ice blocks can cause this water to freeze in the smaller voids and at block-to-block contact points. This often will occur in the first 6 to 8 feet. Also, a strong ice structure can develop in this depth zone due to heat flow to the surface which allows for further solidification of the rubble. Below this depth the blocks will generally form a weaker conglomerate. Rafting of ice of similar thickness will double the local ice thickness.

The location of the ice determines to a great extent how it responds to external forces. The sea ice north of Alaska can be considered as being made up in three zones (see figure 3-7):

1. *the fast ice zone,* which includes the grounded ridges, when they exist and any extension of

Figure 3-7.—Arctic Ice Zones



SOURCE: U.S. Army Cold Regions Research and Engineering Lab, 1984.

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[8] W. F. Weeks and G. Cox, "The Mechanical Properties of Sea Ice, A Status Report," in *Ocean Science and Engineering* (9:2).

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the fast ice resulting from the ice cover being anchored to the grounded ice;

2. *transition ice zone*: a transitional zone between the rotating ice pack and relatively motionless fast zones; and
3. *polar pack ice*: mostly multi-year ice that covers the central Arctic Ocean rotating in a gyre.

The shelf north of the Beaufort Sea is narrow: about 50 miles wide and breaks at a depth of 200 to 225 feet. Shallow waters extend over a large portion of the shelf near Harrison Bay with the 60-foot isobath being about 45 miles offshore. Off Camden Bay in the eastern Beaufort, however, the 60-foot isobath is only about 11 miles offshore.

In the Beaufort Sea, the fast ice generally begins to melt in late May-early June. Near the coast this process is accelerated by rivers flooding over the ice surface. Once the fast ice melts away from the shore, its anchorage is lost and it can be moved by wind and currents. Such movement can cause the ice to break into smaller and smaller floes, further accelerating the dissipation process through melting and by being driven away from the area. Open water frequently exists along portions of the Beaufort Sea coast during the months of July, August, and September. The length of the open water season, however, is variable and is frequently controlled by the prevailing winds. Some seasons the winds drive the pack ice offshore far beyond the continental shelf. In other years, onshore winds keep the pack close to shore. During these summers, coastal shipping can be greatly restricted, even prevented. In 1975, some barges supplying the North Slopes were caught and had to winter over in the ice at Prudhoe Bay.

The grounded ridge zone is an area of considerable pressure ridge formation activity. The shallow depth, however, limits keel depths of the ridges. The grounded ridge zone is not continuous, does not necessarily occur at the same locations each year, and, where such ridges form, the resulting ice rubble may be quite extensive and massive or of minor consequence.

The transitional ice zone is one of great energy. The cracks and leads open and close in this zone as the pack deforms under wind and current drag forces. Pressure ridges are formed from floes driven against one another and from the sliding, shearing action between the various ice masses. Keels formed in these may be driven by a combination of wind, current, and ice interactions into water depths shallower than their keel depths. Here the ice keel can be pushed into the seabed, and like a cutting tool, gouge depressions and furrows in the sediments (see figure 3-8). As this happens repeatedly, the seafloor is completely scarred by ice gouges. In water depths of less than 45 feet, ice gouging occurs very frequently, but in these waters shore currents and storms can cause filling by sediment. Beyond the 45-foot depth, ice gouges are not filled and will remain until altered by later ice gouging. Ice gouge orientation tends to follow depth contours.

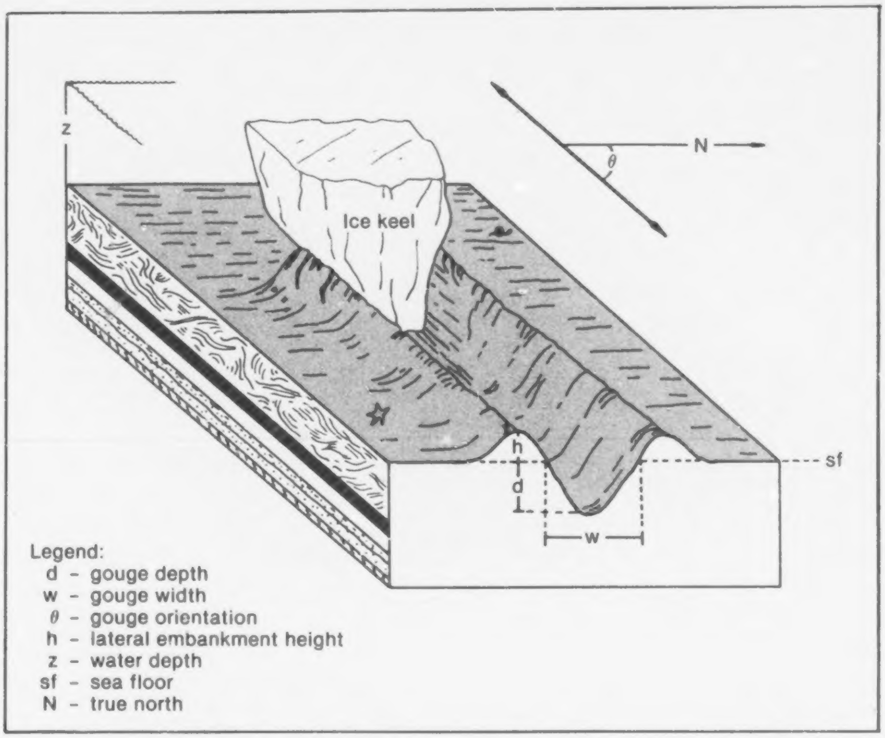
The polar pack region is composed primarily of multi-year ice. However, it too is subject to the interactions of winds, causing leads to open and close. Pressure ridges are continually formed. The ice pack north of Prudhoe Bay drifts clockwise with the movement of the Beaufort Sea Gyre. Ice islands, large icebergs which originate from the northern coast of Ellesmere Island, can also be found drifting within the gyre. These ice islands may be 150 feet thick. Ice islands in this gyre may remain there for decades before leaving the Arctic Ocean. From time to time ice islands are grounded in the coastal waters of the Beaufort Sea.

There are significant differences in the ice in the Bering Sea as compared to the Arctic Basin. The Alaskan shelf south of the Bering Strait is quite wide. The majority of the Navarin Basin lease sale area is in water depths ranging from 300 to 600 feet. Multi-year ice can drift into the northern part of the Bering Sea but even that portion of the sea becomes ice-free during the summer. Ice is formed each year in the northern part of the Bering Sea to thicknesses of about 1 to 2 feet. Fast ice in the very northern Bering Sea may grow to a thickness of more than 4 feet but multiple rafted ice can be over 15 feet thick. Ice starts forming at the shore and extends outward and southward. The edge of the ice may be driven southward by wind forces. Pressure ridging occurs but, like the average ice thickness, is much less than in the Arctic Basin waters. Ridges may have sails of 15 feet above the surface and keels four to six times as deep. Currents through the Bering Strait generally run northward. There is an occasional reversal which can

Photo credit: SEDCO

First mobile offshore drilling unit in U.S. Beaufort Sea—Exxon's Super CIDS

Figure 3-8.—Ice Keel Gouging Sea Floor



(Recent tests indicate gouge depths can vary from 3 feet in shallow lagoons to 15 feet in open ocean water depths of about 100 feet.)

SOURCE: U.S. Army Cold Regions Research and Engineering Lab, Report 83-21, 1983.

bring thicker Arctic Ocean ice with larger features southward. The maximum and minimum extents of the sea ice cover in the seas off the Alaska coast are shown in figure 3-9.

Other ice conditions may be hazardous. When combined with freezing conditions, the winds and waves produce an icing spray which can cause dangerous ice build-up on ships and structures. The interactions of blocks of floating sea ice with waves can propel the ice into the sides of ships and structures resulting in large localized forces. During some atmospheric conditions, fixed wing aircraft and helicopters traveling at critical altitudes can be subjected to icing, creating dangerous situations.

Other Factors

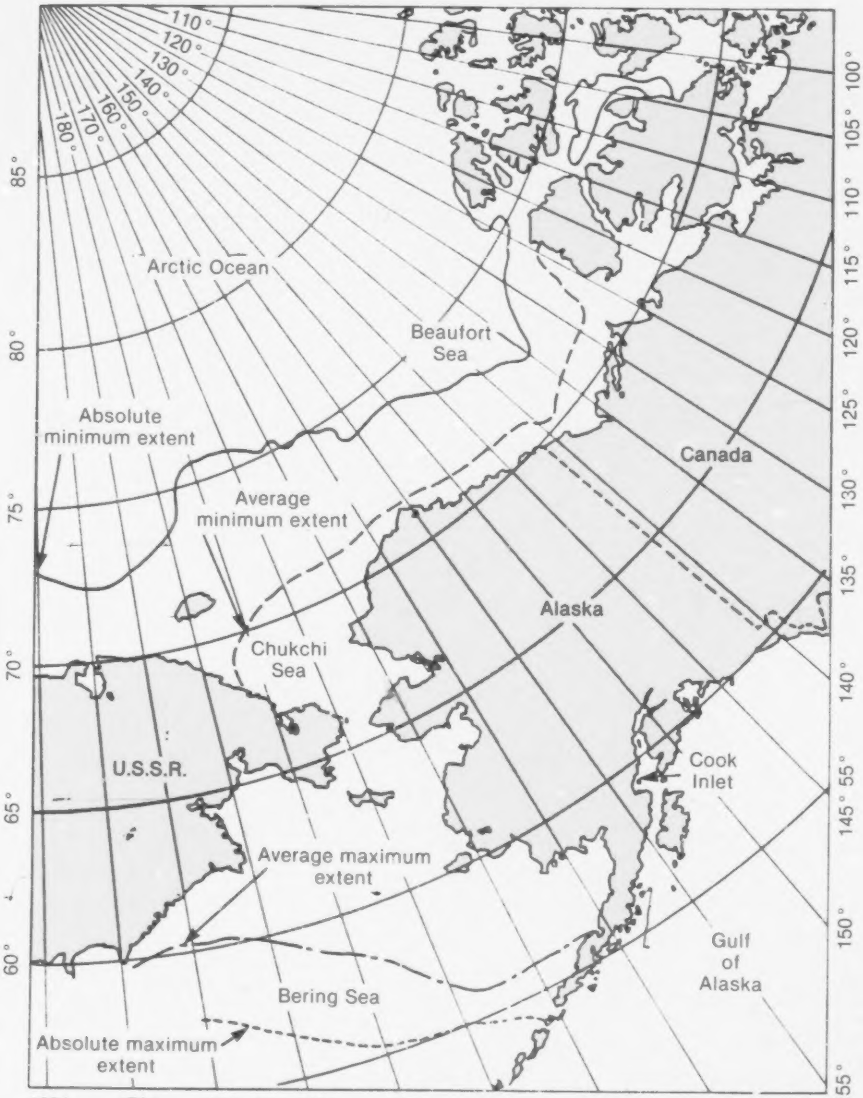
Fine, silty sediments and sub-bottom permafrost are the two geotechnical factors of concern in Arctic waters. Permafrost exists only in the Arctic Ocean. In the southern part of the Bering Sea near the Aleutian Chain, seismicity is also of concern.

The engineering properties of the upper sediments of the ocean floor must be considered in the design of foundations for bottom-founded structures. The possibility of mud slides must be considered in the foundations of structures placed on the steeper slopes of the Navarin Basin. Industry is conducting investigations of the instability of sediments and the design of foundations for these conditions.

Permafrost could affect the design and routing of pipelines in the Beaufort Sea. Some related design problems include the differential thaw subsidence of permafrost and adjacent foundations, thaw subsidence around wells, and frost heaving.

Figure 3-9.—Extent of Arctic Sea Ice

Summer Minimum and Winter Maximum


110°
120°
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170°
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80°
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105°
110°
115°
120°
125°
130°
135°
140°
145° 55°
150°
155°
165°
170°
175° 55° 180°
175°
170°
165°
Arctic Ocean
Beaufort Sea
Absolute minimum extent
Average minimum extent
Canada
Alaska
Chukchi Sea
U.S.S.R.
Cook Inlet
Average maximum extent
Gulf of Alaska
Bering Sea
Absolute maximum extent

SOURCE: American Geographical Society, New York, New York, 1975.

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In general, the Arctic environmental factors affecting the design, installation, and operation of offshore systems vary depending on the season of operation and upon the ice conditions. But data on ice condition, oceanographic, meteorological, and geotechnical factors are relatively sparse for many areas. And, like all Arctic operations, collection of additional data is costly.

Meteorological data are particularly sparse for the areas north of Alaska and in the Bering Sea. Satellites and ice buoys are used to obtain ice movement and weather data for the regions north of Point Barrow. However, much of the sensory data do not have the resolution necessary for many applications. Unfortunately, most of the visual sensors are usable only during the daylight summer months, and even then their effectiveness is lowered due to clouds and fogs that develop above melting ice and evaporating ice melts. The lack of sufficient ice and meteorological data has severely limited the ability to detect and forecast ice movement and weather conditions for the Arctic region.

Technology Development

OTA has developed three Arctic scenarios to illustrate the approaches that may be used to develop and produce Alaskan oil discoveries, based on today's knowledge of the environment and suitable technology (see box). A complete production system for these conditions does not currently exist. Because of the very high costs involved, there is a significant incentive to improve system reliability and cost effectiveness by using advanced technologies. A range of engineering development, tests, and evaluation may be required before industry can safely and economically produce possible petroleum discoveries in hostile offshore Arctic environments.

Figure 3-10 illustrates some of the production platform systems and structures that currently appear to be the most favored alternatives for each of the Alaskan offshore planning areas. In each case, the system is based on operating experience in a related situation or a similar environment.

Technology for exploring, developing, and producing oil and gas in offshore Arctic environments appears to be progressing at a pace compatible with government leasing schedules and industry's contemplated development schedules. Prior to a sale in a planning area, industry usually proceeds with research and engineering programs to develop baseline data, design criteria, and engineering designs for exploration and production systems which match the expected conditions. This research and engineering effort is intended to: 1) establish the feasibility of systems and the confidence that these systems can be constructed and operated safely; 2) estimate system costs to guide in economic evaluations of the resource prospects, and thus help establish the lease bid level; 3) identify key site-specific information needed for system selection and design if oil and gas discoveries are made; 4) ensure that post-lease sale exploration, development, and production could be brought onstream on approximately the time table assumed in pre-lease sale economic analyses; and 5) enable industry to move quickly to drill exploration wells.

After the discovery of economic reserves resulting from exploratory drilling, considerably more research and development, data collection, and testing is necessary for industry to move into the development and production phases in the Arctic. Some research and development areas are more critical than others, especially when economics are considered. The following areas are judged to be important to future Arctic development.

Ice

Additional research is needed to obtain basic data on ice properties and ice strengths under different conditions as actually encountered in the field, on the strength characteristics of pressure ridges and of the ice within such ridges, and on variations of ice properties.

Although data on ice and its properties are high on the list of needed research, there is a significant data base on ice strengths and properties. Industry is developing more data on ice feature size and geometries and conducting model tests to investigate ice/structure interactions. Ridges are being sampled, their ice strengths determined for the appropriate ridge thermal profile, and ridge temperatures are being monitored throughout the year. In almost all cases, exploratory drilling structures are instrumented to measure the loads exerted by

Arctic Technology Scenarios

In order to assess the technology associated with exploration, development, and production of oil and gas in the Arctic frontier of the Outer Continental Shelf, OTA developed three scenarios that describe a range of potential environments, technologies, and base systems that could be typical in these areas.

For each scenario, OTA also developed time and cost estimates for all phases of exploration and production. These estimates were discussed at OTA technology workshops and then modified based on comments from workshop participants. Cost estimates for the scenarios were derived from the 1981 National Petroleum Council report, adjusted for 1984 dollar equivalents. These estimates, however, are indicative only of broad cost ranges; more precise and reliable costs can be derived only when a specific discovery is delineated and a production system designed for a particular site and set of operating conditions. These cost estimates, and variations on them for different field sizes, also are used in chapter 5 to analyze economic factors.

The Arctic scenarios are for three areas: the Harrison Bay area of the Beaufort Sea (Lease Sale 71), the Norton Basin (Lease Sale 57), and the Navarin Basin (Lease Sale 83). Data were collected about environmental conditions, and assumptions made about exploration, development and production, infrastructure and support services, and transportation for these scenarios. The general considerations related to those assumptions are discussed below.

The schedules start with the date of the lease sale and end with peak production—a time span ranging from 11 years for Norton Basin to almost 15 years for Harrison Bay. These assumptions are optimistic in that they are based on the minimum times for obtaining the necessary governmental approvals. Some industry experts believe that as much as 2 or 3 additional years should be added to the schedules to allow for all permitting and approvals.

OTA estimated the total costs of exploratory drilling to range from $435 to $825 million for the three Arctic scenarios. Total capital costs for development of the prospects in the three scenarios were estimated to be from $2 to $11 billion, including the cost of drilling development wells, obtaining equipment, and building islands or platforms. OTA estimated total operating costs during the production phase at $102 million per year for Norton Basin, $168 million per year for Harrison Bay, and $240 million per year for Navarin Basin. Abandonment costs were estimated to range from $200 million to $1.1 billion.

Environmental Considerations

Environmental conditions in the Arctic strongly influence the technology scenarios. These conditions include temperature, ice, amount of daylight in the winter, distance from shore, water depth, and other factors such as storms, waves, and soils.

Extremely low temperatures, such as those found in Harrison Bay, have a significant impact on working conditions and operating practices. Clothing must be designed to protect workers adequately and survival gear must be provided at operating sites such as gravel islands in case travel is disrupted. Working areas must be enclosed, and outdoor jobs scheduled carefully. In such conditions, special low-temperature steel must be used to avoid failures in brittle steel, and equipment must be operated continuously to ensure proper viscosity oil and lubricants. In the Navarin basin, the cold temperatures combine with high winds and waves to cause spray icing on upper structures.

Ice conditions—including duration, thickness, and movement—are perhaps the most critical of the environmental considerations because they govern design and access. In the Norton Basin, for example, dynamic ice movement imposes significant constraints on structure design. In Harrison Bay, the shore fast ice zone limits ice movement to some extent, but the offshore pack ice still will transmit thermal stresses and forces that result in some movement, and dynamic floe impact forces may be transmitted to frozen-in structures during severe storms. Floebergs, multi-year floes, and ice island fragments also may drift into the nearshore waters of Harrison Bay and become frozen into the fast ice. In Navarin Basin, the 450-foot water depths and high waves combined with ice forces could impose large forces acting to overturn bottom-founded structures. Although such structures are installed in the North Sea at equivalent depths, they are not subject to the horizontal ice forces that would be encountered in the Navarin Basin, and Arctic structures would require additional strength margins.

Ice and temperature conditions also affect transportation and support services. In the Navarin Basin, the frequency of ice ridges are important for tanker design, because large thick ice floes or areas of rafted ice can be avoided or their effects mitigated by icebreakers. In Harrison Bay and Norton Basin, keels from pressure ridges could penetrate the seabed, requiring pipelines to be buried beneath gouge depth. Although no major marine pipeline systems exist in Arctic waters, trenching by subsea plows and pipeline installation by the bottom tow method are considered feasible. In Harrison Bay, however, permafrost precautions would be necessary to prevent the hot oil from melting the permafrost and possibly causing soil subsidence. While these conditions have been handled successfully onshore on the North Slope, pipeline trenching into subsea permafrost 10 to 20 feet deep would require costly and massive machinery not yet built or tested. As a result, most plans for developing nearshore fields in the Beaufort Sea favor building a causeway to support a pipeline to shore.

Soft soils—a potential problem in some areas of Harrison Bay and the Navarin Basin—could require either soil strengthening or more elaborate foundation designs. Potential approaches used elsewhere to overcome soft soils include piles, wicks or drains, replacing the soil with gravel, cement infection to strengthen soils, larger bearing surface areas for gravity structures, and dredging out the soft sea bottom to reach firmer soil underneath. Structures for soft sea bottoms have been designed for pre-lease sale technology verification and structure costing in Navarin Bay, but extensive site-specific soil surveys would be required for final design of bottom-founded or gravity structures.

Finally, strong bottom currents and storm waves and surges will be critical design considerations for structures, pipelines, and support systems in the Norton and Navarin Basins. In the Norton, storm waves can cause liquefaction in some of the finer sediments (e.g., those found near the Yukon delta). In the Navarin, which has the most severe winds and waves of all the Alaskan Arctic planning areas, a semi-submersible drilling unit—the most stable platform under severe weather conditions—would be required. The unit would maintain its position with anchors where bottom conditions are suitable, or with dynamic positioning equipment including computer-controlled main propulsion and thruster units and acoustic signals emitted by beacons on the seafloor. Similar semi-submersibles have been used successfully in the North Sea and eastern Canada under severe weather conditions.

Exploration

The type of exploratory drilling rig is determined by site and environmental conditions. As noted above, exploratory drilling in the Navarin Basin would require a semi-submersible. In Harrison Bay, a gravel island (similar to those already in use in the nearshore areas of the United States and Canadian Beaufort Sea) would be used, with the gradual slope and reinforcing sandbags protecting against the erosive action of water and ice. In 50 feet of water, such an island would be 300 to 400 feet in diameter at the top with a gradual slope to the seafloor base diameter of approximately 1,000 feet. Elevation above water level would be about 20 to 25 feet. Alternatives to the gravel island platform include mobile structures such as CIDs which is now in use in the Beaufort Sea. In Norton Basin, open water season is long enough to permit exploratory drilling from a jackup rig and the operation would be similar to those using jackups in the North Sea or eastern Canada.

Development

The technology for field development is determined by site and environmental conditions, as well as the size of the field. However, design requirements for production structures are more stringent than those for exploration due to the larger investment in wells and the longer service life of the equipment. The 20- to 30-year life of a field implies a greater probability of encountering more severe environmental conditions (e.g., the 100-year storm).

The scenarios assume that gravel islands (possibly with cassion-retained protection) would be used for field development in Harrison Bay and Norton Basin, and gravity platforms in Navarin Basin. The oil would be treated on the gravel islands or gravity platforms, and stored in either onshore or offshore storage tanks (Harrison Bay and Norton Basin) or in gravity structures (Navarin Basin). Alternatives to gravity storage now under consideration by industry include moored tankers tied to an icebreaking, single anchor leg mooring; totally subsea storage; and steel jacket platforms with internal storage.

Large gravel islands may become prohibitively expensive as water depth increases beyond 50 or 60 feet. An alternative preferred by some is the bottom-founded gravity structure similar to those used in the Canadian and U.S. Beaufort Sea for exploratory platforms. Designs are proposed for many types of these structures including conical shapes to reduce ice forces. Another advantage of such a structure is the ability to construct it in one piece at a shipyard and then tow it to the site for installation, thus lowering onsite construction costs substantially.

Infrastructure and Support Services

In addition to the severe environment, the primary consideration in designating infrastructure and support services is the distance of the field from established bases onshore. For example, the established facilities at Prudhoe Bay provide the basic infrastructure for operating in Harrison Bay. Work camps, maintenance shops, living accommodations, and catering operations already exist, and procedures for working and coping with the environment have been established. However, reliance on the Prudhoe Bay infrastructure as the sole support base could have prohibitively high transportation costs, and a satellite base closer to Harrison Bay would be needed.

Some support for Norton Basin exists at Nome, but it is not nearly as extensive as at Prudhoe. In anticipation of increased oil activity, Nome plans to build a deepwater harbor—a causeway with docking facilities. Alternatively, Dutch Harbor could be used as the support base.

Navarin Basin poses the greatest logistics problems of the three scenarios because it is so remote. Dutch Harbor on Unalaska Island in the Aleutians—a World War II Navy base and already a base for oil company exploration operations and a center for fishing activity—could be a support base for Navarin. Dutch Harbor is ice-free so all necessary supplies and equipment could be transported there by conventional cargo vessels year-round. It also is a potential location for a storage and transshipment terminal. Other developed Aleutian harbors such as Cold Bay have been considered but at present lack sufficient harbor facilities or water depth. Even Dutch Harbor, however, is too far from the Navarin Basin to be the sole support base, and a forward base may be established on either St. Matthew Island or St. Paul Island. Use of St. Matthew Island poses environmental and regulatory concerns because it serves as a wildlife refuge.

Transportation

Selection of combinations of transportation modes are governed by the southern markets to be served, reliability, magnitude of field development, costs, and the availability of spare TAPS capacity as North Slope onshore production begins to decline in a few years. The most likely transportation scenarios for the three production areas were chosen. Critical considerations include offshore pipeline depth sufficient to avoid ice scour and ice keel gouging, and permafrost protection for subsea pipelines in Harrison Bay, and the cost of various tanker and terminal variations for long-distance transshipments from Norton and Navarin Basin. Some recent industry studies have shown that use of ice-reinforced tankers with icebreaker suport is the most cost effective system for Navarin and Norton. Also, the use of a transshipment terminal does not appear economical until production rates go beyond 1 million barrels per day.

Arctic Scenarios

Parameters	Harrison Bay	Norton Basin	Navarin Basin
Environmental conditions:			
Temperature and wind chill	Extremely low: −47° F, 15 knot winds; −90° F wind chill temp.	Moderately low: −36° F, 11 knot winds; −72° F wind chill temp.	Low: −11° F, 25 knot winds; −54° F wind chill temp.
Ice conditions	Severe: 10-month coverage; within shore fast ice zone; plane fast ice 7 ft, rafted ice 22 ft, ridges 75 ft	Moderate: 8-month coverage; smooth ice 3.5-4 ft, rafted ice 15 ft, ridges 75 ft; dynamic ice movement	Light-moderate: 5-month coverage; smooth ice 3 ft, rafted ice 12-18 ft; ridge frequency more critical than thickness
Winter daylight	None in Dec.-Jan., 2.5 hr/day in Nov., 6.5 hr/day in Feb.	Some	Some
Approximate distance from shore	20 mi	40 mi	400-700 mi
Water depth	50 ft	50 ft	450 ft
Other	Permafrost precautions to prevent melting and subsidence	Strong bottom currents, storm waves and surges; potential for gas-charged sediments	Severe storms, wind-driven waves, spray icing, remoteness poses extreme logistics problems; soft soils potential
Exploration:			
Number of wells	6	6	6
Type of rig	Arctic land rig on gravel island[a]	Jackup	Semisubmersible
Development:			
Peak production rate (B/D)	500,000	125,000	500,000
Type of platform	Gravel island[a]	Gravel island[a]	Gravity platform[b]
No. of platforms/islands[c]	7	4	7, plus 2 service
Number of rigs	2 per island	2 per island	2 per platform
Total number of wells[c]	271	136	271
Field size (billion barrels)	2.0[d]	0.5	2.0[d]
Initial production (B/D)	4,000	2,000	4,000
Infrastructure and support services:			
Support base	Prudhoe Bay; closer satellite base	Dutch Harbor; some facilities in Nome	Dutch Harbor or Cold Bay; forward base on St. Matthew Island or St. Paul Island; 2 advanced service bases
Air service	Daily, Deadhorse (Prudhoe Bay area), Fairbanks and Anchorage	Commercial airport in Nome	Commercial airport in Nome; helicopter from forward base
Land access	Year-round—Dalton Hwy from Fairbanks; winter ice roads on land fast ice	None	None
Sea access	Annual sealift for barges in open water season (Aug.-Sept.)	Deepwater harbor planned in Nome; Dutch Harbor ice-free year-round for conventional cargo vessels	Deepwater harbor planned in Nome; Dutch Harbor ice-free year-round for conventional cargo vessels
Transportation:			
To shore	Pipelines—buried beneath gouge depth with permafrost protection	Onshore or offshore storage tanks to offshore deep draft mooring and transfer terminal for onloading to 250,000 DWT ice-reinforced tankers with icebreaker escorts	Storage in gravity structures;[e] offshore deep draft mooring and transfer terminal for onloading to 150,000 DWT ice-reinforced tankers with icebreaker escorts[f]
Onshore	Along-the-shore pipeline connects with TAPS offshore; or pipeline to west coast of Alaska with ice-reinforced offshore tanker terminal		

[a] For 50 ft water depths and greater in Harrison Bay and Norton Basin, several alternatives to gravel islands exist and may be preferable depending on gravel availability, exact water depths, soils, and other site-specific conditions. The alternatives are concrete, steel, hybrid structures built as caissons or complete bottom-mounted units.

[b] Principal alternative platform is a steel, pile-founded structure; choice depends on site conditions.

[c] The number of platforms and wells selected for each scenario is probably a minimum. Total number of wells includes injectors.

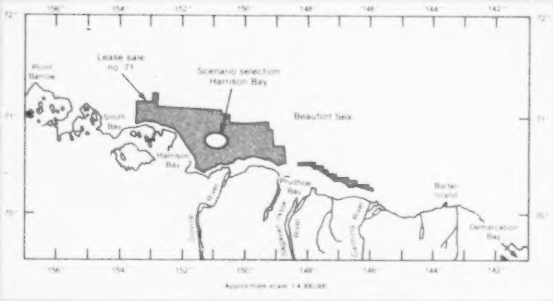
[d] Such a large field size is rare, and this assumption is disputed by industry experts. This report does not assume that this is the most likely field size, but only indicates how development might proceed with such a field size.

[e] Gravity platforms have been used in the rough weather conditions in the North Sea with a large background of experience for firmer soil conditions and no ice.

[f] Transportation alternatives include a pipeline to St. Matthew Island or one of the Pribilof Islands for transfer to tankers, use of a transshipment terminal in the Aleutians, and use of icebreaking tankers.

SOURCE: Office of Technology Assessment.

Harrison Bay Scenario
(Beaufort Sea)


156°
154°
152°
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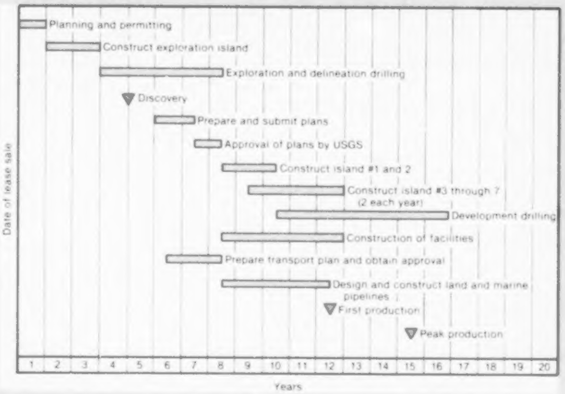
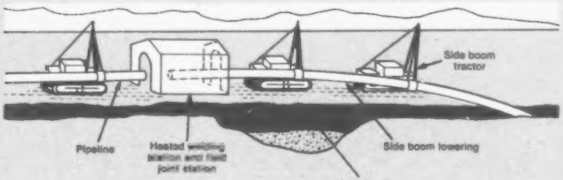
148°
146°
144°
142°
72°
71°
70°
Lease sale
no. 71
Point
Barrow
Scenario selection
Harrison Bay
Smith
Bay
Beaufort Sea
Harrison
Bay
Colville River
Prudhoe
Bay
Sagavanirktok River
Canning River
Barter
Island
Demarcation
Bay
Approximate scale 1:4,300,000

Location of discovery



Schedule

Gravel Island exploration and production platforms


Side boom
tractor
Pipeline
Heated welding
station and field
joint station
Side boom lowering
Ice trench

Laying a pipeline through a trench cut in the ice

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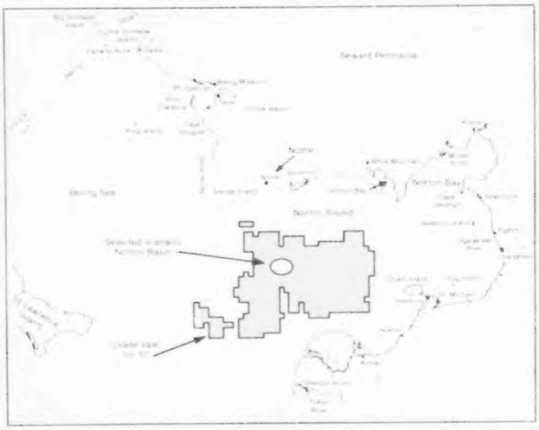
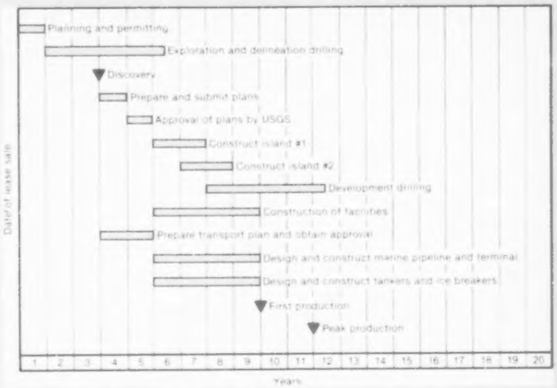
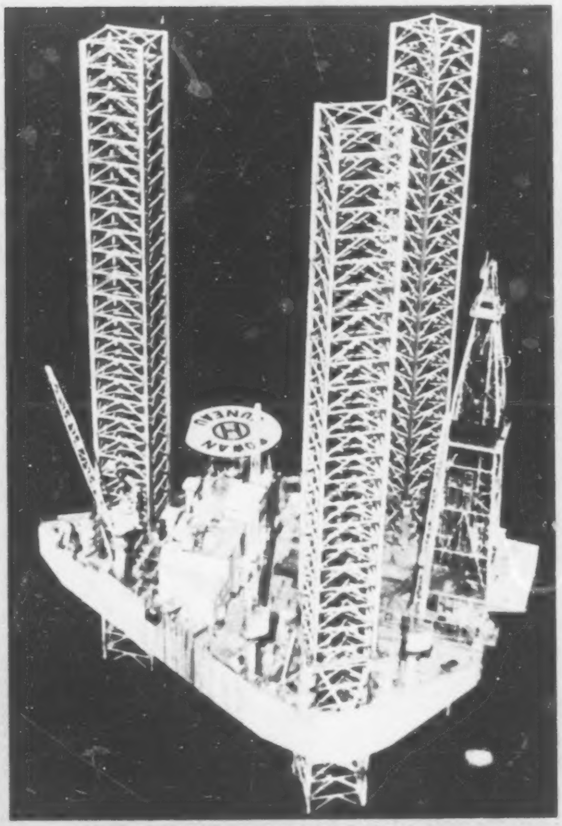
Norton Basin Scenario
(Northern Bering Sea)


Seward Peninsula
Nome
Norton Bay
Bering Sea
Norton Sound
Selected scenario Norton Basin
St. Michael

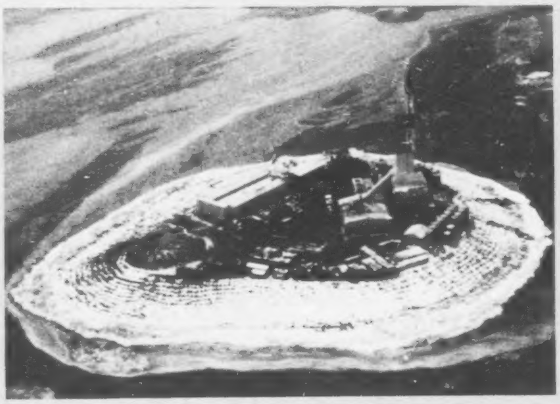
Location of discovery



Schedule



Jack-up exploration rig



Gravel Island production platform

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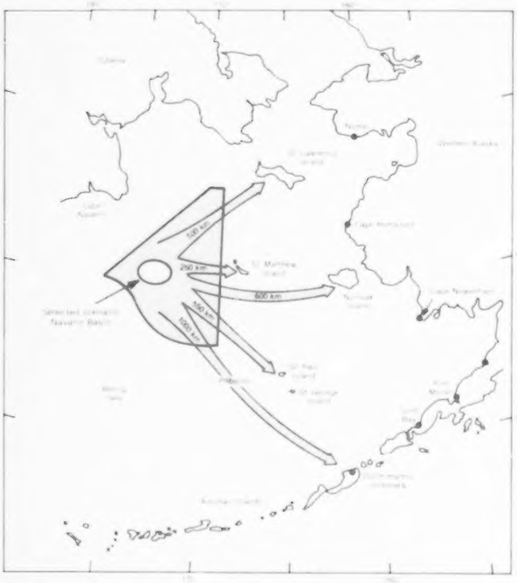
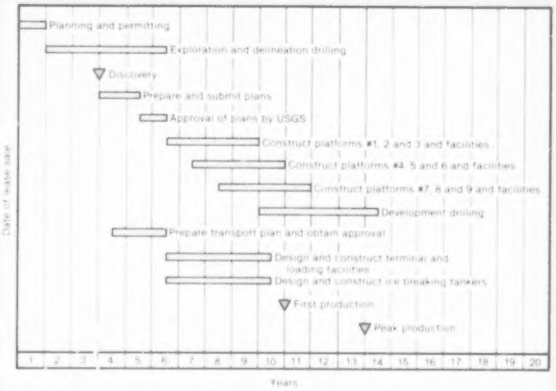
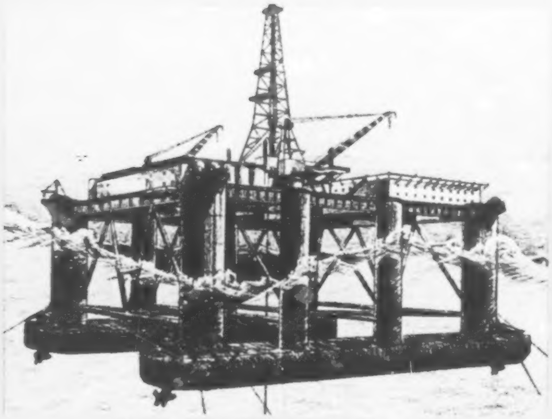
Navarin Basin Scenario
(Central Bering Sea)


Nome
Western Alaska
St. Lawrence Island
St. Matthew Island
Nunivak Island
Selected scenario Navarin Basin
250 km
600 km
1000 km
St. Paul Island
St. George Island
Bering Sea
Aleutian Islands

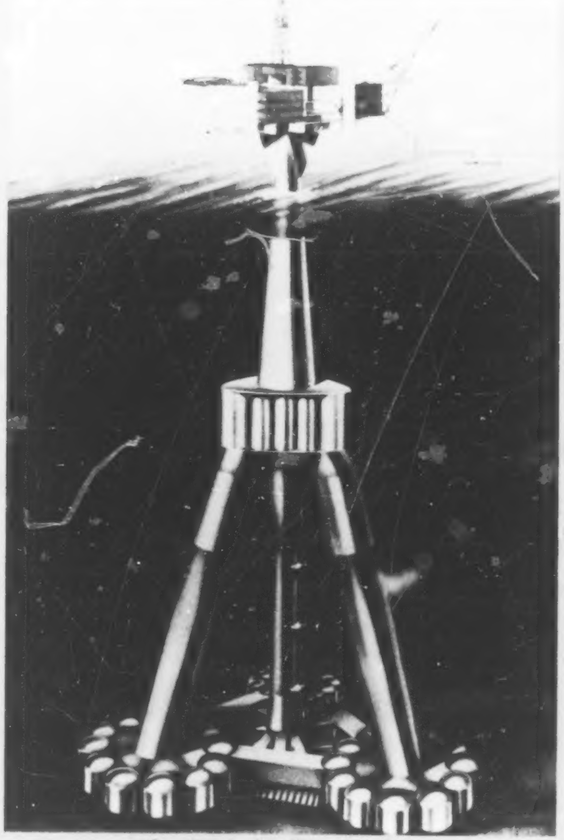
Location of discovery



Schedule



Semisubmersible exploration rig



Gravity production platform

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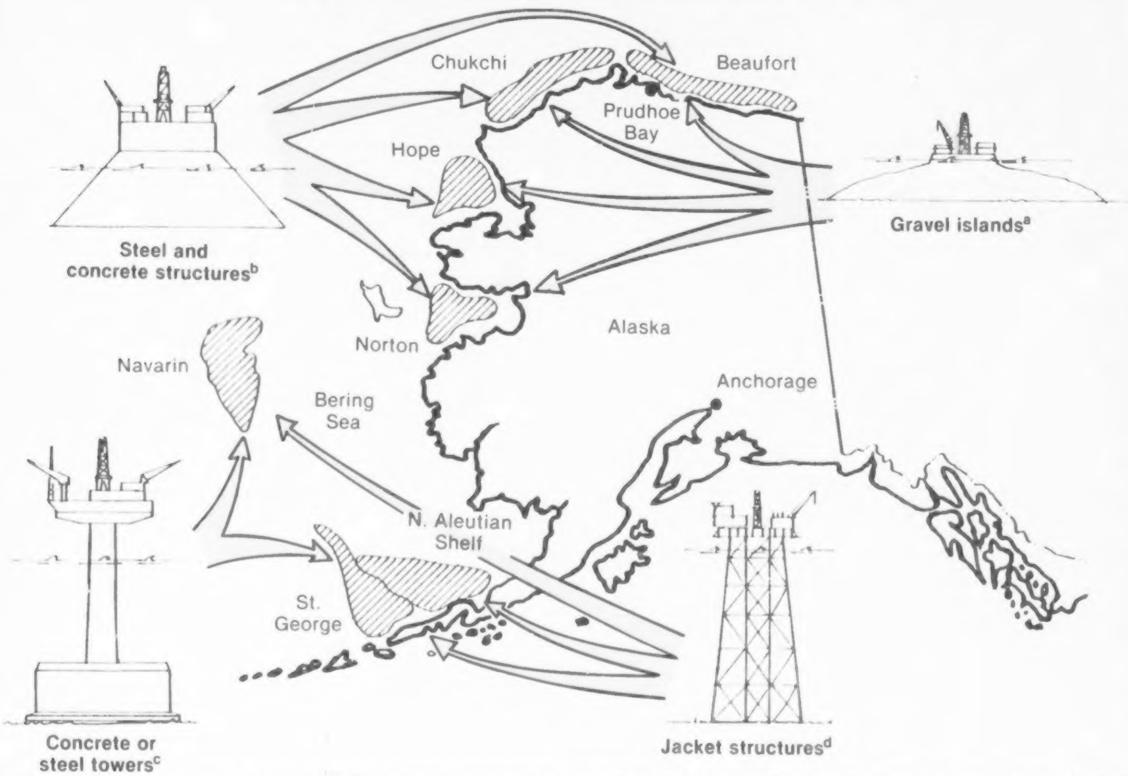
Figure 3-10.—Alternative Arctic Production Structures



[a] Most offshore exploratory drilling has been done from these man-made islands and the first offshore development (in 40 ft. water) is likely to use a gravel island platform.
[b] One such cassion-type platform now in operation in Alaskan Beaufort for exploratory drilling (CIDS).
[c] These types of structures would be extension of technology developed for North Sea.
[d] These structures may be extension of both North Sea and Cook Inlet developments.

SOURCE: Proceedings: DOI-EEZ Symposium, Nov. 1983.

sea ice. Other programs have made use of natural islands to make load measurements.[9]

Ice Reconnaissance

Increased surveillance from satellites and by aircraft is needed to provide real time data. Ice surveillance is important for structural design purposes, logistics, and tanker transportation design and planning. Many companies have utilized all relevant satellite data to describe ice conditions. Ice movements have been measured for several years by wireline movement stations and drift buoys. Helicopters and fixed wing aircraft are used to assist in making ice forecasts for operations that could be hampered by ice invasions.

Marine Pipelines

More rapid and effective trenching techniques below ice-gouge depths, and rapid and effective techniques for alignment, connection, and repair of pipelines are essential. Recognizing that Arctic pipelines are a critical future design problem, more cost-effective installation techniques and designs for areas with warm subsea permafrost are being investigated. Repetitive surveys are being conducted in the Beaufort Sea to assess gouge depths and the rate at which gouges are being filled by wave and ice actions on the seafloor.

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[9] Artic Petroleum Operators Association, *Description of Research Projects* (Calgary, Canada, 1982 and 1983); American Society of Mechanical Engineers, *Proceedings of the Offshore Mechanics and Arctic Engineering Symposium* (New Orleans, 1984); and *Proceedings of the Offshore Technology Conference* (May 1984).

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Photo credit: Mobil Oil Co.

Concrete gravity platform in the North Sea

Tankers

Development of design data to permit more confidence in the design of icebreaking tankers, especially those which could successfully operate in the Beaufort and Chukchi Seas on a year-round basis, will be important.

Seismicity

For two of the planning areas, St. George and North Aleutian Basins, a unique problem exists concerning strong motion seismic (earthquake) activity associated with the subduction of the Pacific plate beneath the North American plate. Research is needed to collect seafloor response data, to develop wave propagation and attenuation models, and to establish soil response characteristics.

Those projects are indicative of the scope of research and engineering programs underway by the oil industry. In addition to programs that are proprietary to individual companies, over 275 joint industry programs that deal with wide-ranging aspects of Arctic technology have been undertaken by member companies of the Alaska Oil and Gas Association (AOGA) (see table 3-4). Many Canadian design projects, strength tests, and model tests are also applicable to the U.S. offshore.

Table 3-4.—Summary of Cooperative Arctic Research Projects

				Area			
Subject	N. Aleutian	St. George	Navarin	Norton Sound	Chukchi	Beaufort	General
Ice properties, physical	0	5	15	14	14	62	—
Ice properties, mechanical[a]	—	—	—	—	—	—	15
Waves	3	4	2	2	1	9	1
Currents	2	3	3	4	1	7	—
Geotechnical	6	4	2	4	2	11	2
Structures	2	4	7	4	4	17	19
Oil spill	—	—	—	—	—	3	9
General technical[b]	—	—	—	—	—	1	14
Transportation[c]	—	1	2	2	1	6	2
Cost wells	1	2	1	2	—	—	—
Whale mammals	—	—	—	1	—	3	1

[a] Ice Mechanical property studies are considered common to all lease areas.
[b] This includes equipment used for research, such as stress sensors, and operations, i.e., ice movement detectors and measurement devices.
[c] This includes pipeline and tanker studies.

SOURCE: Alaska Oil and Gas Association (AOGA), Technical Subcommittee of the Lease Sale Planning and Research Committee, January 1985.

THE DEEPWATER FRONTIERS

Overview

The petroleum industry has developed technologies incrementally as exploration and production have moved from shallow to deepwaters. In this progression, as the severity of the environment has increased, additional design requirements have been recognized. To meet these requirements, offshore structures have become larger and more costly. The logistic support for construction and operation has likewise increased. Government agencies have also had to increase their capabilities to monitor industry's activities to assure safety and environmental protection.

This section discusses technologies for oil and gas development in water depths greater than 1,320 feet. There has been extensive exploration at such depths but no production to date. Many of the technologies required for deepwater production are available although not applied commercially at this time. As new technologies are applied to deepwater frontier areas, testing and verification will be needed. Some new concepts may be abandoned and others developed further. Safety is a major concern in offshore engineering and construction. Technologies used must provide reliability, not only to assure human safety but also to minimize the risk of losing a platform or other structure and to minimize operational costs.

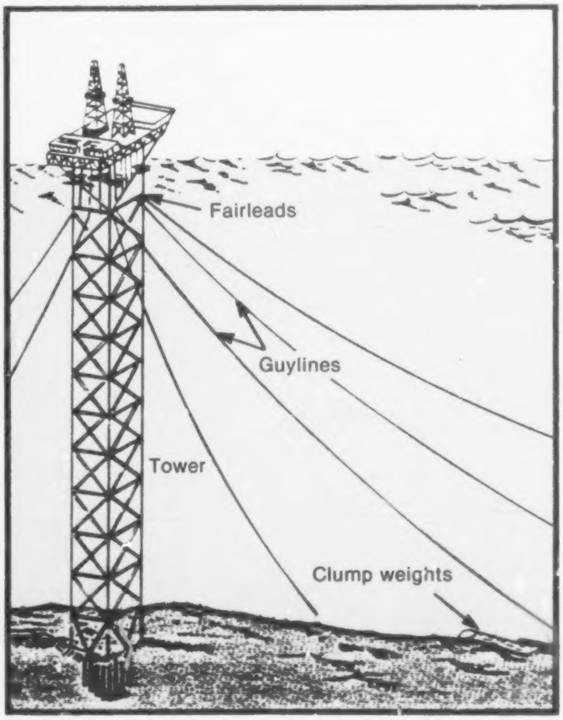
A number of technological areas are critical in deepwater petroleum development. These include: 1) structural design, which ranges from the metallurgy of the steels or composition of materials used, through welding techniques and ocean floor platform foundation engineering; 2) techniques for installation, maintenance and repair of structures, risers, and pipelines; 3) drilling, well control, and completion; and 4) technologies for support operations, such as diving and navigation. Human diving capability is limited to approximately 1,640 feet, with only experimental dives to 2,300 feet. Thus, one-atmosphere manned vehicles and remotely controlled unmanned vehicles may become increasingly important for support services. Navigation technologies are important during seismic surveys, exploration drilling, and platform and pipeline installations. This includes acoustic, radio, and satellite technologies for seismic survey navigation; directional drilling; and ship, submersible, and remote vehicle operations.

Historically, the offshore petroleum industry has a good record of developing adequate technology to meet ever more challenging conditions as development has moved to more hostile environments farther offshore. Some existing systems—especially compliant platforms and subsea wells—have the capability of fairly direct extension to deeper water. Others—e.g., deepwater risers, control and well maintenance technologies—may need further development for use in deep water.

New technological achievements are being made continually as new resource discoveries are made in deeper waters. For example, in Norske Shell's Troll Field in 1,148 feet of water in the North Sea, a large concrete gravity structure is under detailed design and testing. Exxon has initiated production from its Lena guyed tower in approximately 1,000 feet of water in the Gulf of Mexico (see figure 3-11). Other structures are planned for Gulf of Mexico discoveries in up to 1,500 feet of water.

In addition, advanced conceptual designs exist and some component testing has been accomplished for systems to be used in water depths up to 2,000 to 2,500 feet. Among these systems are Exxon's submerged production system, Chevron's subsea wellhead system, and Conoco's tension leg platform. It is reasonable to expect that in a few years several types of structures and production systems will be built for use in these water depths.

Figure 3-11.—Guyed Tower



Beyond about the 2,500-foot depth, there has not yet been as much activity aimed at developing specific production systems because opportunities for significant petroleum discoveries at that depth are still more speculative. However, oil exploration in deepwaters of the U.S. Exclusive Economic Zone (EEZ) is underway. Sonat's drillship Discover Seven Seas drilled for Shell Offshore, Inc., in water depths of more than 6,000 feet in the Wilmington Canyon area of the Atlantic coast during 1983-84. Other leases have been sold in the Atlantic with water depths of about 7,500 feet. Blocks were leased in water depths of approximately 5,800 feet in the April 1984 Gulf of Mexico sale. And blocks in approximately 10,000 feet of water are now being offered offshore California.

Deepwater achievements of various system components are shown in table 3-5. The history and status of subsea well and facility water depth records are shown in figure 3-12.

Based on its deepwater drilling and production achievements, the petroleum industry believes that there are no significant technological limits to operations in up to 8,000 feet of water. Petroleum basins which are developed in the deepwater frontiers will require new technologies which will be deployed for the first time. Because these new systems are being developed continually, it may not be reasonable to establish water depth or other regulatory limits based on present technologies. But sufficient precautions must be taken to assure that the gov-

Table 3-5.—Deepwater Drilling and Production Achievements (through March 1985)

Component or activity	Record water depth experience to date (feet)	Place, date
Exploratory drilling	6,952	U.S. Atlantic, 1984
Development drilling	2,500	Mediterranean, 1983
Fixed steel/production platform	1,025	Gulf of Mexico, 1978
Guyed tower production platform	1,000	Gulf of Mexico, 1983
Floating production platform	460	Tunisia, 1982
Tension leg platform	485	North Sea, 1984
Subsea wellheads	1,007	Brazil, 1984
Subsea production system	500	North Sea, 1982
Deepwater pipeline	2,060	Sicily, 1979
Tanker loading systems	530	North Sea, 1980

SOURCES: *Proceedings of the Offshore Technology Conference* (1984); USGS Circular 929; *EEZ Symposium Proceedings* (November 1983); *Ocean Industry* (July 1984); *Engineering News Record* (Aug. 16, 1984); *Oil and Gas Journal* (July 16, 1984 and Oct. 15, 1984).

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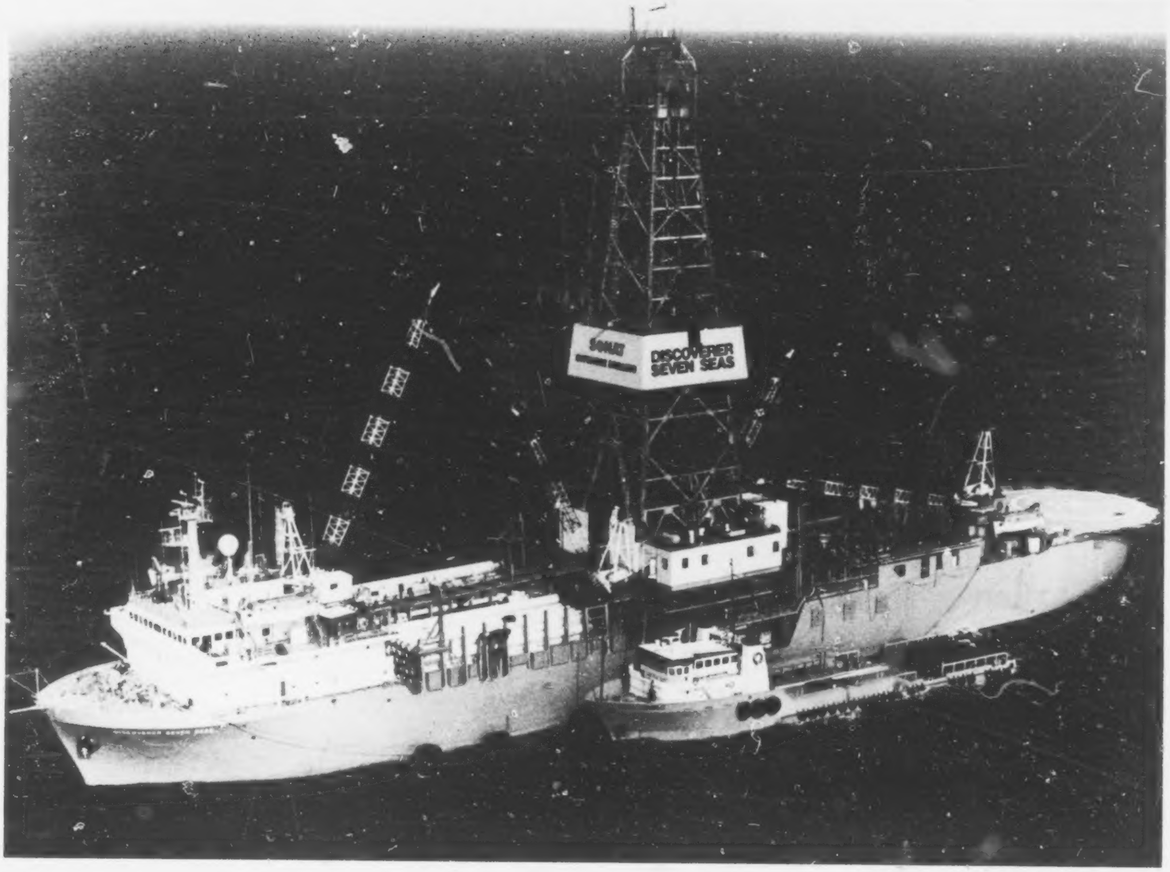
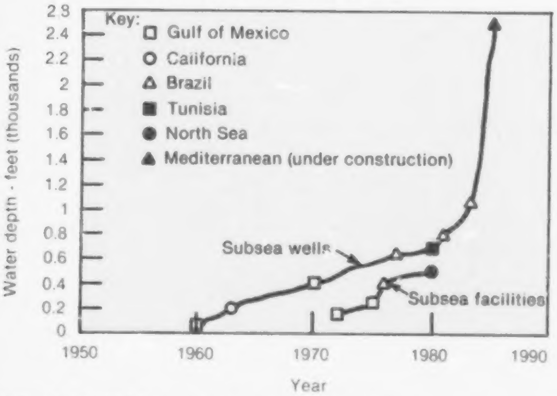


Photo credit: Shell Oil

Deepwater drillship "Discoverer Seven Seas" which drilled at record water depths in the Mid-Atlantic during 1983-84

ernment regulations imposed on offshore operations are appropriate and the responsible government agencies monitoring offshore operations have the skills and technology necessary for judging the adequacy of industry's engineering designs, equipment, and procedures.

Figure 3-12.—Subsea Wells & Production Facilities History and Current Status



SOURCE: DOI EEZ Symposium, November 1983; update 1984

Field Characteristics

The three key offshore planning regions including deepwater frontier areas are the Atlantic, Gulf of Mexico, and the Pacific. This section describes the field characteristics for these three regions.

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Atlantic

Since there have been no commercial oil discoveries in the Atlantic region, it is not possible to predict the field characteristics. There is reason to believe, however, that some of the reef formations present in the Bay of Campeche, Mexico, may extend northward to the deepwater basins in the Atlantic. If this is the case, oil fields could be similar to the prolific offshore fields with high well flow rates now producing in Mexico. If such fields were found in the Atlantic, it would be a significant commercial discovery.

Gulf of Mexico

The Gulf Coast reservoirs range in size from very small (less than 5 million barrels of recoverable oil) to major oil fields of over 100 million barrels. The median oil field size is 29 million barrels and the mean size is 66 million barrels. Of the 105 analyzed oil fields, 21 are over 100 million barrels. These reservoirs also vary widely in other characteristics. Formations often consist of unconsolidated sands which require gravel packing and hole conditioning. Generally, production rates are modest. A 1,500-barrel-per-day well in the Gulf of Mexico is considered very good. Drilling rates (feet per day) are high. This high drilling rate may not be sustainable in deepwater if the upper formations require several casing strings to be set near the surface. More often 4 weeks is required to drill a deepwater well. As experience is gained, these deepwater operations may speed up.

Pacific

All the known West Coast oil fields lie off central and southern California. Many of these fields produce relatively heavy oil. In addition, the oil often contains sulfur. The West Coast oil is shipped to the Gulf Coast for refining.

Drilling is slower and more difficult in this region. Structures are often faulted and are hard to delineate. However, there are some very large and productive fields in California. The Point Arguello field is one of the largest discoveries in U.S. (Outer Continental Shelf (OCS) history. Recoverable reserve estimates range from 400 to 500 million barrels, and combined field flow rates are projected to reach 160,000 barrels per day by the end of the century. In addition, total flow rates from the fields off Santa Barbara County are expected to reach 450,000 barrels per day by the early 1990s. The east Wilmington field further south in Long Beach produces 120,000 barrels per day. These three fields have the highest production rates in the lower 48 States.

West Coast drilling rates offshore are slow by comparison with the Gulf Coast. A typical offshore well requires 6 to 8 weeks to complete. Gravel packing is often necessary. If more than one reservoir is present at a drill site, the casing may be perforated to enable the wells to produce from multiple zones.

The low gravity, asphalt-base oil means that processing facilities are complex. This, coupled with the thick formations, makes the typical West Coast platforms larger than Gulf Coast platforms. Sixty-well platforms are common, and large expensive production facilities are the norm. It can be expected that this trend will continue in deep water.

Environmental Conditions

Important environmental parameters that affect the design of production platforms and systems are summarized in table 3-6 for the Atlantic, Gulf, and Pacific regions. These values are based on general industry practice. Conditions that are peculiar to a specific region are discussed below.

Table 3-6.—Deepwater Environmental Design Conditions

Region	Maximum wind velocity** (knots) (1 hour duration)	Maximum 100 year wave height (feet)	Typical current velocity* (surface to 200 ft.) (knots)
Atlantic	90	85	3.0
Gulf	90	70	3.0
Pacific	60	60	2.0

*Exact value of current velocity varies and is highly dependent on precise location, particularly in the Atlantic and Gulf.

**For 10 meter elevation; higher elevations may be subject to higher velocities and gusts.

SOURCE: Office of Technology Assessment.

Atlantic

Hurricanes, other severe storms, and the Gulf Stream are major environmental factors in the Atlantic region. The Gulf Stream presents problems in both exploratory drilling and for production systems if commercial discoveries are in areas affected by its currents. The current velocity is up to 5 knots near the surface and in the range of 3 knots to a depth of more than 1,000 feet. This high current velocity may require streamlined risers for exploratory drilling and must be considered in the design of compliant structures if they are used. The major impact of the Gulf Stream is confined to the southern portion of the Atlantic region. The Mid-Atlantic and North Atlantic areas are only slightly affected since they are not in the main stream of the current. However, warm core eddies may spin off the Gulf Stream and affect systems in these areas.

Seafloor instability, especially on the Continental Slope, may require that specific sites be avoided or that special foundation stabilization techniques be used and/or developed. Other environmental conditions in the Atlantic region generally are less severe than in the North Sea and more severe than in the Gulf of Mexico. The design methods, as well as the operational experience gained from the Gulf, probably can be upgraded to meet Atlantic development requirements.

Gulf of Mexico

Hurricanes are also a major environmental factor in the Gulf of Mexico. Industry has a great deal

Photo credit: Scripps Institution of Oceanography

Rough seas are an important environmental design condition in offshore frontier areas of experience in designing fixed offshore structures to withstand the high winds and waves generated by these intense storms, and this experience recently has been applied to Exxon's Platform Lena which is a compliant structure. Mud slides are another unusual environmental factor in the Gulf. These slides may cause foundation instability in some areas. Another factor is the Gulf of Mexico loop current and the eddies which are produced by that current. These eddies affect operational practices and the design of structures since they may cause vibrations which could lead to metal fatigue or other failures. Generally, in the Gulf, there is a wealth of experience to draw upon as development moves into deep water.

Pacific

The wind and wave conditions in the Pacific region are less severe than either the Atlantic or the Gulf of Mexico, but earthquakes are a factor which must be considered in system designs. Design criteria and analytical methods have been developed for the entire West Coast, and these have been applied successfully to numerous offshore structures. Earthquakes should not pose serious problems for properly designed compliant structures since the natural vibration response periods of these structures are well outside the high energy portion of the earthquake spectrum. Soil characteristics must also be considered in system designs for the Pacific region because of the steep slopes present in some areas.

Technology Development

Exploratory Drilling

The offshore drilling industry currently has a fleet of 13 drillships and semi-submersibles capable of drilling in waters deeper than 3,000 feet. Of these, four drilling units are capable of drilling in 6,000 feet of water and one in 7,500 feet of water.

Several technical advances have made this deepwater capability possible. These include: 1) dynamic positioning utilizing controllable pitch thruster propulsion units and computerized automatic station-keeping systems (see figure 3-13); 2) reentry systems utilizing television and sonar instead of guidelines; 3) electrohydraulic blow out preventer control to reduce signal transit time; and 4) marine risers equipped with syntactic foam buoyancy material and improved riser couplings.[10]

Limitations to exploratory drilling in very deep water come primarily from environmental conditions and a low formation fracture gradient. Excessive current velocities (approximately 5 knots or greater) could prevent some dynamically positioned drilling units from maintaining their position because of the large amount of power required to counteract such forces. Also, wave heights exceeding 20 feet can interrupt drilling operations from a dynamically positioned drill ship. Some of these limitations may be overcome through the use of a dynamically positioned semi-submersible with substantially greater station-keeping capability than existing vessels. Abnormally high formation pressures, particularly at shallow formation depths, can also cause difficulty in deepwater drilling and could limit or prevent development of some deepwater reserves.

Field Development

Nearly all offshore fields to date have been developed using fixed-leg platforms. During the 1970s, industry progressed from the capability to design and install fixed-leg platforms in about 400 feet of water to design and installation for the current record depth of 1,025 feet for Shell's Cognac platform in the Gulf of Mexico. Designs also have been completed by Exxon for a fixed-leg platform for installation in 1,200 feet of water in the Santa Barbara Channel. Technically, fixed-leg platforms can be built for a water depth of 1,575 feet or more. However, due to the large amount of steel required and limitations of fabrication and installation methods, there is probably an economic limit for these structures at a water depth of about 1,480 feet.[11]

There are several concepts for extending water depth at which production systems can be installed; for example, the guyed tower, the buoyant tower,

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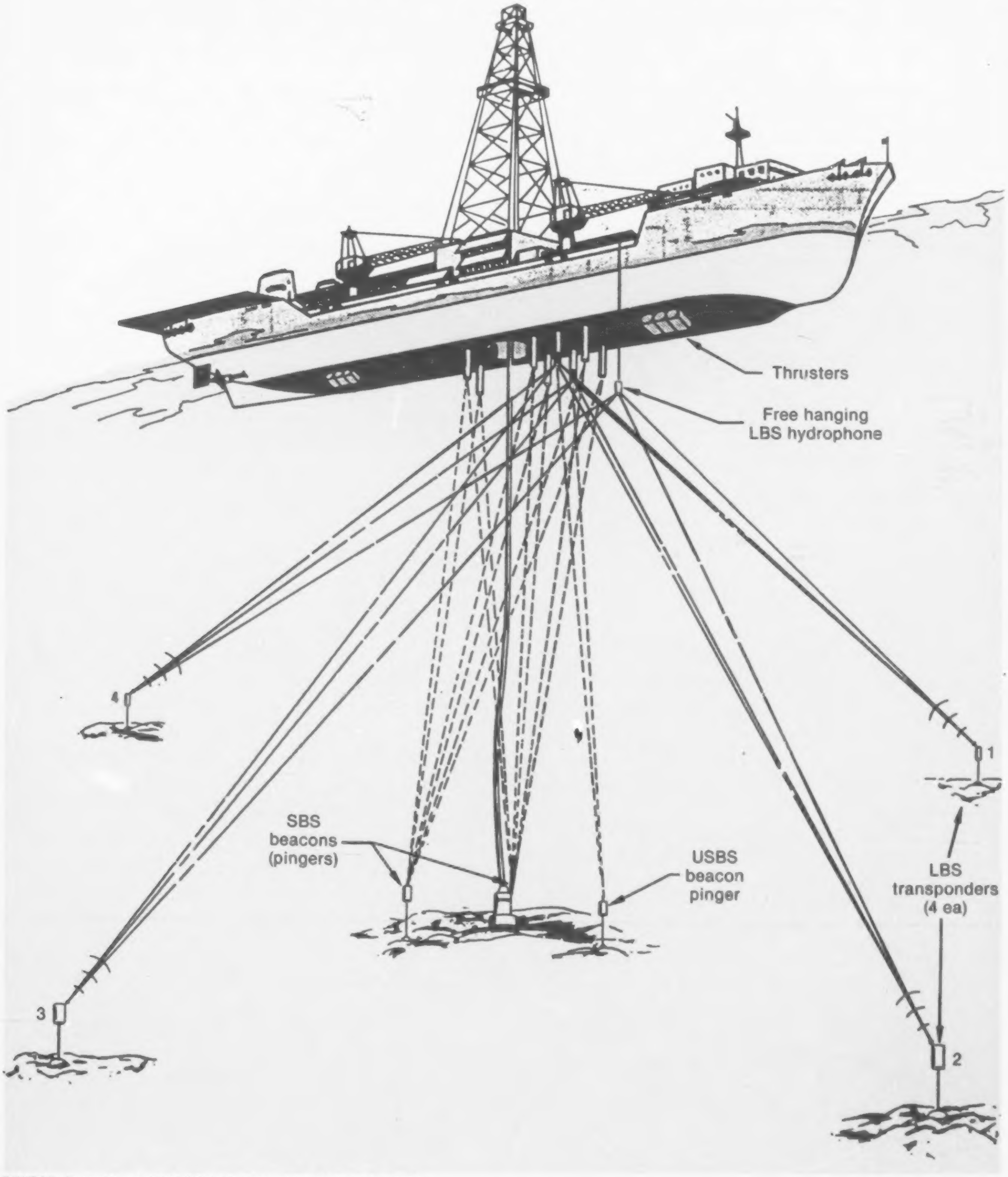
[10] A. S. Johnson and G. O. Smith, "The Technology of Drilling in 7,500 Feet of Water" (Society of Petroleum Engineers, Paper 12793, 1984); and J. C. Albers, "Exploratory Drilling Systems" (Outer Continental Shelf Frontier Technology Symposium, 1979).

[11] F. P. Dunn, "Deep Water Drilling and Production Platforms in Non-Arctic Areas" (National Academy of Sciences, 1980); and R. L. Geer, "Engineering Challenges for Offshore Exploration and Production in the 1980s" (BOSS Conference, 1982).

Figure 3-13.—Dynamic Positioning for Deepwater Drilling


Thrusters
Free hanging LBS hydrophone
4
1
SBS beacons (pingers)
USBS beacon pinger
LBS transponders (4 ea)
3
2

SOURCE: Proceedings of the Offshore Technology Conference, 1984

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the tension leg platform, and the subsea production system. All but the subsea production systems are "compliant structures," which are designed to move slightly with environmental forces of wind, waves, and current as opposed to conventional structures which rigidly resist such loads.

The guyed tower is a tall, slender structure that requires less steel than a fixed-leg platform. Guy lines or anchor lines are used to resist lateral forces and to hold the structure in a nearly vertical position. Exxon has recently installed the first guyed tower, Lena, in 1,000 feet of water in the Gulf of Mexico. The platform, with space for 58 wells, is secured with 20 guy lines, eight main piles, and six perimeter torsion piles.[12] Current technical opinion is that guyed towers are structurally and economically feasible in water depths to about 2,500 feet. Beyond these water depths, the guyed towers will require much greater amounts of steel to maintain an acceptable stiffness.

The buoyant tower is a tall, slender structure like the guyed tower but is maintained in a vertical position by large buoyancy tanks rather than by guy lines. Rotation at the base is accounted for either by an articulated joint or by a flexible foundation.

The tension leg platform is a floating platform fixed by vertical tension legs to foundation templates on the ocean bottom. OTA has selected a tension leg platform for its hypothetical deepwater scenario (see box). Buoyancy is provided by the pontoons and columns of the hull. The buoyancy that is in excess of the platform weight maintains the legs in tension in all loading and environmental conditions. The floating hull of the tension leg platform, similar to that of a semi-submersible, is secured at each corner by a number of so-called tendons. The hull pulls up on the tendons so that they never go slack, even in the trough of the maximum design wave and when carrying maximum operating loads.

The substantial advantage of the tension leg platform is its relative low cost sensitivity to increases in water depth. The principal design influence of increasing water depth is in the tendon and riser lengths, with the hull size and weight increasing relatively slowly with water depth. The main disadvantages of a tension leg platform are the operational complexity of its well and tendon systems relative to fixed platforms and its limited deck load capacity.

The first tension leg platform was installed in 1984 by Conoco in 485 feet of water in the North Sea. This probably is not an economical water depth for a tension leg platform, but its installation in the North Sea will provide the experience and information needed to successfully install these units in deeper waters.

Practical application of tension leg platforms will start where it is no longer economically attractive to construct a fixed-leg platform. This water depth is estimated to be around 1,500 feet, depending on location. For intermediate depths of 1,000 to 2,500 feet, the guyed tower is thought to be the attractive alternative. Theoretical maximum water depths for tension leg platforms are estimated by Conoco to be 6,000 feet by the year 1990 and 10,000 feet by the year 2,000.

Subsea production systems are also a major alternative for deepwater field development. With these systems, wells are drilled from a floating rig and completed on the seafloor. Several such systems have been extensively tested in operations in shallow water. These include Exxon's system in the Gulf of Mexico (see figure 3-14), Hamilton's Argyll Field in the North Sea, and Shell/Esso's system in the Cormorant Field in the North Sea.

Currently, there are more than 100 offshore subsea well installations in operation in water depths of up to 960 feet. An additional 36 subsea well completions currently are scheduled for installation.[13] One of these is a subsea well completion by Chevron offshore Spain in a water depth of 2,500 feet.

Subsea well completions can be either "wet" or "dry" systems. The wet system is relatively insensitive to water depth and can be installed in deepwater in the same manner as shallow water. Its application is limited only to the water depth capability of the floating drilling unit and the flowline installation technique. In the dry system, the well head

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[12] P. H. Kelly, F. B. Plummer, and P. J. Pike, "The Lena Guyer Tower: A Pioneering Structure" (Proceedings of the DOT Conference, 1983).

[13] M. Tubb, "1983 Subsea Completion Survey," Ocean Industry (October 1983).

Deepwater Technology Scenario

To assess deepwater technology, OTA selected one hypothetical prospect located offshore the central California coast approximately 38 miles west of Point Conception in water 3,000 to 4,100 feet deep. Assumptions about field conditions, exploration and development, infrastructure and support services, and transportation for this deepwater scenario are shown in the accompanying table. It should be noted that the assumptions made for this area are illustrative, and actual conditions may vary substantially. The oil accumulation could be deeper, the gravity of the crude could be sour, and well spacing might need to be closer. All of these factors would increase the cost of development and change the technical approaches chosen for this scenario.

Schedule

The schedule begins with the lease sale and ends with the completion of development drilling—a total of 13 to 14 years. First production is assumed to occur 10 years from the lease sale date. This schedule is probably optimistic because it assumes the minimum time to obtain the necessary governmental approvals. It also assumes that detailed design of the platform will begin at the time of discovery and proceed concurrently with permitting and approval. Timeframes would also increase if the area is more difficult to develop than postulated (e.g., heavier crude, sour crude, noncircular field), or if two platforms are required instead of one.

Exploration and Development

Water depth in the scenario area is within present industry capabilities for exploration. Several dynamically positioned drilling units, ship-shape and semi-submersible, currently are able to drill exploratory wells in water depths of 6,000 to 7,500 feet. Drilling units of this type are equipped with computer controlled main propulsion and thruster units. The unit is kept on location by these thrusters with positioning data from a continuous acoustic signal emitted by one or more beacons located on the seafloor. The use of this dynamic positioning equiment has made these drilling units independent of the constraints imposed by a mooring system.

Development of a discovery in a water depth of 3,000 to 6,000 feet appears to be technically feasible but has not yet been achieved. Several development methods are possible, including tension leg platforms, floating production systems, and subsea production systems. The method selected for this scenario is the tension leg platform with surface completed wells. These have been designed for water depths up to 3,000 feet, but there has not yet been a commercial discovery in such depths. A subsea production system is an alternative for this scenario but most designs to date are not self-contained units; storage and processing facilities would be required on a separate platform. Satellite subsea wells oculd be used in conjunction with a tension leg platform especially with a more elongated field shape.

Sixty directional wells would be drilled from the tension leg platform and would have individual conductors from the ocean bottom to the lower deck for completion and hook-up in a manner similar to (although operationally more complex than) methods used for fixed, bottom-founded platforms. Alternative designs provide for incorporation of the conductors inside the mooring legs or for completing the wells on the seafloor. With the latter method, an ocean floor manifold would be required and one or two risers would bring oil to the surface.

Transportation and Infrastructure

For environmental reasons, California State prefers a subsea pipeline rather than shuttle tankers to transport crude oil to shore. Deepwater pipelaying capability has advanced to where the technology (but not the actual equipment) exists to install a 20-inch pipeline in water depths of 7,500 to 10,000 feet. However, actual experience has been limited to water depths of about 2,000 feet. A tensioned 20-inch pipeline riser would be installed between the ocean floor template and the deck of the tension leg platform. The pipeline would be connected to the riser through a pull-in assembly.

This scenario assumes that all production would be treated to pipeline quality on the platform, which would involve the installation of oil, gas, and water separation and treatment equipment onsite. An alternate approach is a joint industry trunkline carrying an oil-waste emulsion for treatment onshore, with the gas not used for fuel reinjected into the formation for pressure maintenance, and the water treated to EPA standards and discharged overboard.

Support of a single exploration and development operation in the central California offshore area would require at least one supply vessel, one crew boat, and one helicopter. The crew boat would also function as a standby boat, and would transport small supplies to the rig. The helicopter would be used for routine transportation of drilling crews and small supplies.

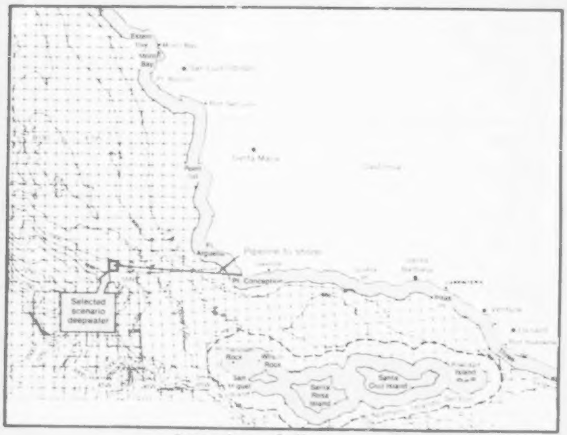
Deepwater Scenario

Parameters	Offshore California
Field conditions:	
Water depth	3,000 to 4,000 ft
Water depth at platform	3,300 ft
Distance from shore	30 mi
Top of producing zone	8,900 ft subsea
Producing zone thickness	800 ft
Type of crude	Sweet
Crude gravity	28° API
Gas-oil ratio	1,000
Exploration:	
Number of wells	6
Type of rig	Dynamically positioned drillship
Development:	
Type of platform	Tension leg platform[a]
Number of platforms	1
Number of rigs	2
Total number of wells	60 (directional)
Well spacing	80 ac
Maximum inclination	59°
Recoverable oil reserves	300 million barrels
Initial well production rate (B/D)	2,000
Peak field production rate (B/D)	70,000
Decline rate	10 percent
Infrastructure and support services:	
Support base	Port Hueneme, CA
Supply vessel	Standard 180 ft without anchor handling equipment
Crew boat	120 ft, operating out of Carpenteria, CA
Air service	Helicopter out of Santa Maria or Santa Barbara
Transportation:	
To shore	Subsea pipeline, 38 mi long, 20 in diameter[b]

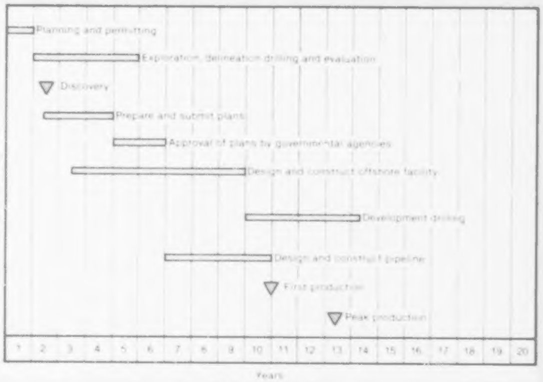
[a] Alternatives include floating production vessels and subsea production systems.
[b] Preferred for environmental reasons; alternative is shuttle tankers.

SOURCE: Office of Technology Assessment.

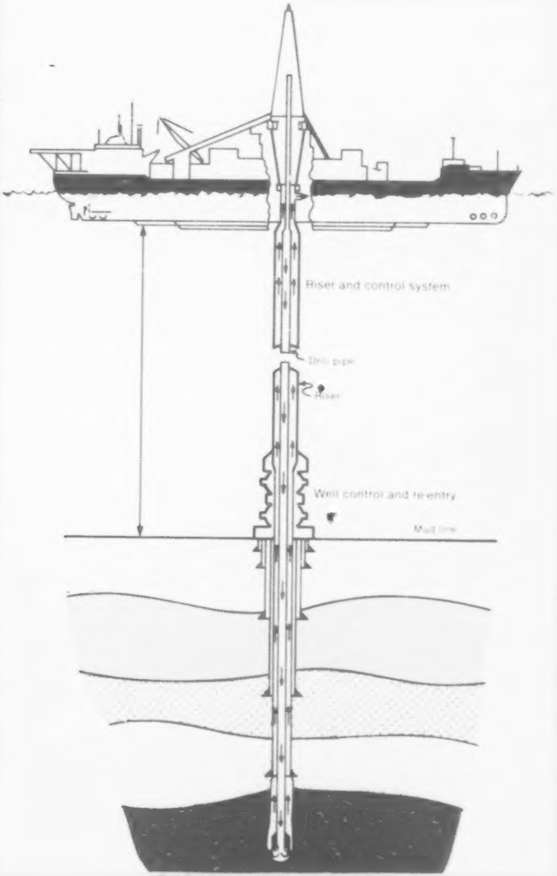
Deepwater Scenario (Offshore California)


Morro Bay
San Luis Obispo
Pt. Buchon
Port San Luis
Santa Maria
California
Point Sal
Pt. Arguello
Pipeline to shore
Pt. Conception
Santa Barbara
Ventura
Oxnard
Port Hueneme
Selected scenario deepwater
Wilson Rock
San Miguel Island
Santa Rosa Island
Santa Cruz Island

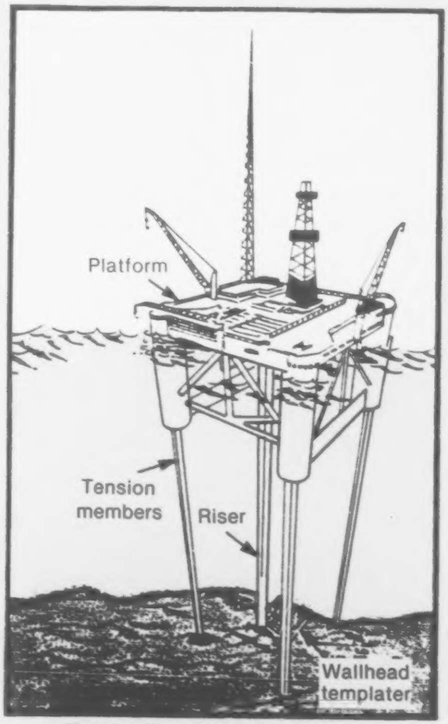
Location of discovery



Schedule


Riser and control system
Drill pipe
Riser
Well control and re-entry
Mud line

Drillship exploration rig


Platform
Tension members
Riser
Wallhead templater

Tension leg production platform

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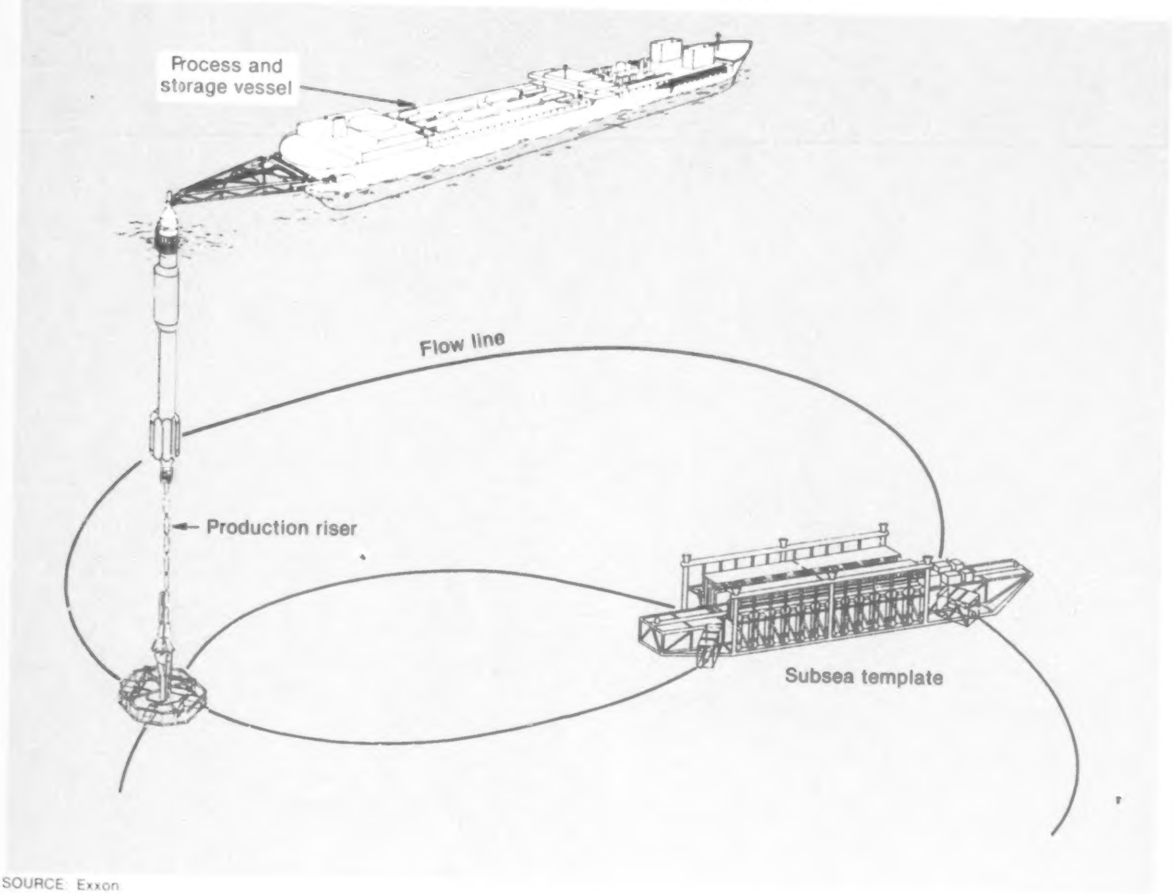
Figure 3-14.—Subsea Production System



SOURCE: Exxon.

is housed in a dry, atmospheric chamber on the seafloor. Flowline connection and maintenance work can be performed by workmen inside the chamber in a normal atmospheric, shirt-sleeve environment. The workmen are transported to and from the chamber in a tethered, atmospheric diving bell which mates to the chamber allowing completely dry access for nondivers. Current development of subsea systems seems to favor the wet instead of the dry system.[14]

Most of the subsea installations are single well completions with the well producing through a flowline to shore or to a fixed or floating platform. In a few installations, the subsea wells are tied into an underwater manifold with a common production riser to a floating production unit. One such system is represented by Shell/Esso's Underwater Manifold Center recently installed in 500 feet of water in the North Sea (see figure 3-15). This system provides for a number of subsea wells clustered on an underwater template with associated manifolding and control equipment. Maintenance operations are performed with a remote vehicle connected to a production platform located several miles away.[15]

An inherent limitation of the subsea production system is the need to have surface facilities to proc-

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[14] Robert C. Visser, "Deep Water Drilling and Production Capabilities," Department of Interior Hearing (May 1977).

[15] T. Bastiaanse and J. R. Liles, "Overview of the Central Cormorant Manifold Centre Project (1974-1983)," Proceedings of the Offshore Technology Conference (1983).

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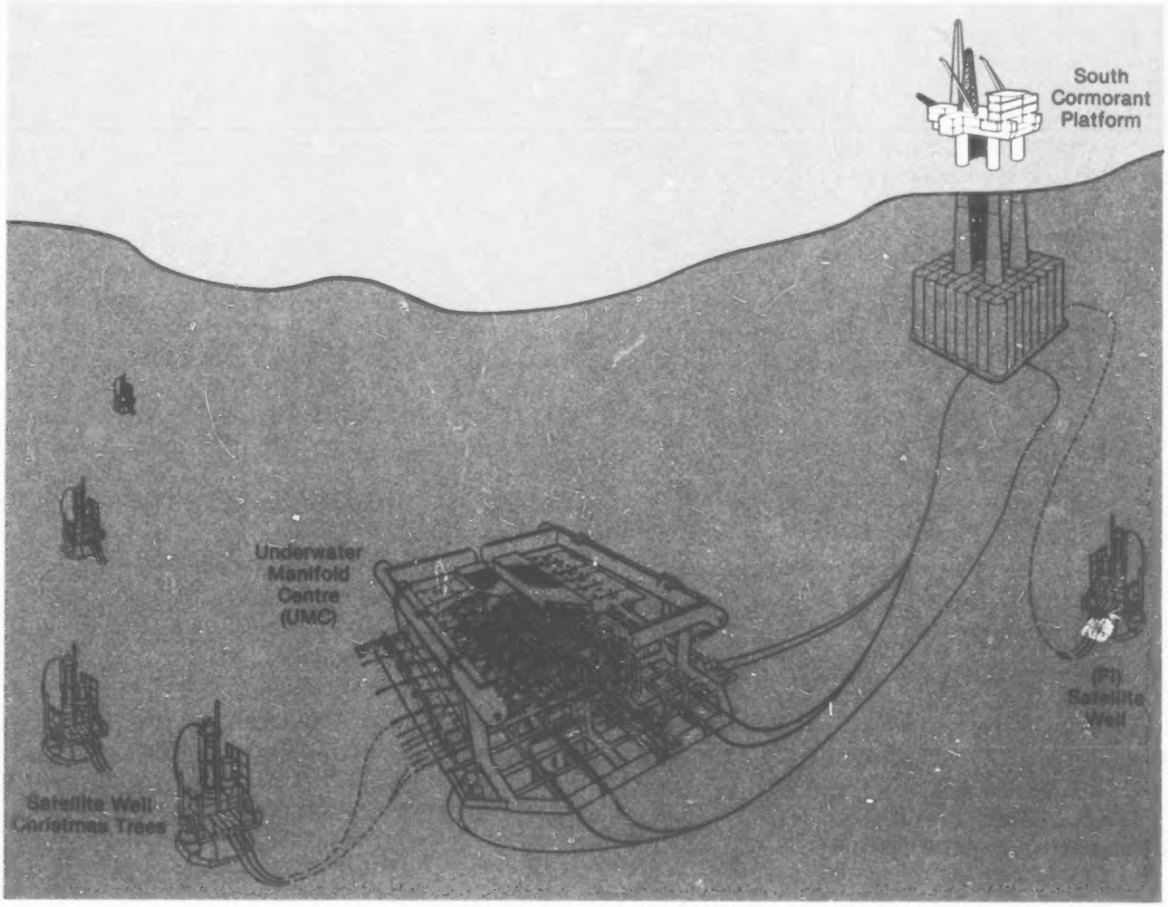
Figure 3-15.—Underwater Production System


South Cormorant Platform
Underwater Manifold Centre (UMC)
(FI) Satellite Well
Satellite Well Christmas Trees

ess the oil and gas for transport to market. Additionally, all well work that cannot be handled by thru flow-line techniques requires an expensive, floating platform. Artificial lift to bring the product to the sea surface is complex and difficult to maintain with hydraulic or electric pumps. However, gas lifting is suitable for these subsea wells. The application of subsea production systems is expected to be more suited to the development of satellite reservoirs where oil can be routed to a preexisting platform.

One of the assumptions that was made for OTA's deepwater scenario was an essentially circular field. This enables the use of a single tension leg platform from which directional development wells can be drilled to fully develop the discovered reserves. In reality this is rarely the case and, particularly with a long and narrow field, it may be desirable to use subsea completed wells in conjunction with a tension leg platform. This approach may make it possible to more completely drain the reservoir and to develop a deepwater field more economically.

Transportation

Conventional pipelaying techniques such as the lay barge, reelship, surface tow, and bottom tow will require adaptation before they can be applied to deepwater situations such as those involved in offshore California. While deepwater pipelaying capabilities have improved considerably, driven particularly by the need to lay pipelines in deepwater

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areas of the Mediterranean, such techniques and required equipment are not fully developed, widely available, or in commercial demand. Semi-submersible, ship-shape, and more conventional barge-shape hulls have been used in the current generation of deepwater pipelay vessels. Other more advanced vessel designs are based on inclined ramp or J-curve methods as opposed to using the conventional "stinger." Bottom-tow or flotation techniques are also considered viable deepwater techniques.[16]

Pipelay capabilities have advanced considerably in order to deal with the specific problems attached to deepwater pipeline installations. These problem areas include: pipe failure due to propagating buckle phenomenon, longer unsupported span lengths, higher strain levels, more severe sea states, longer pipe exposure time during pipelays, and the need for greater accuracy in the control of vessel motions, new mooring techniques, and new classes of thicker diameter pipe.

In general, most of these problems have been successfully solved or are being solved through improved techniques, equipment modifications, or changes in basic technological applications. Vessels capable of laying pipe in deep water may now incorporate the following features: automatic position control systems; high tension capacity; advanced mooring systems; automatic welding, including single-station pipe joining or double joining capability; large pipe storage capacity; and use of computer simulations to optimize a pipelaying spread.

At the present time, it appears feasible that pipelines up to 20-inch (51 centimeters) diameter can be laid in water depths of 4,000 feet using existing or slightly modified equipment, although proven installation has taken place in only 2,000 feet. Saipem's dynamically positioned semi-submersible pipelayer Castoro SEI laid 3 20-inch lines across the Strait of Sicily in the Mediterranean in 1979 in waters to 2,000 feet.

An alternative to pipeline transportation of the crude oil to shore is the use of a floating storage and loading system from which shuttle tankers would move the crude to market. A variety of systems have been developed to provide floating offshore storage and/or treatment and loading systems for transferring oil to shuttle tankers. Offshore storage and loading systems were initially designed to allow continuous production in areas with severe weather conditions or with deep trenches inhibiting pipelines such as in the North Sea. These systems now have been greatly expanded or modified to aid in the use of subsea production systems, to allow marginal field development, and to initiate production from a field as early as possible.[17]

Floating ship-shape or semi-submersible production facilities and combined production/storage/loading facilities recently have become attractive to offshore operators. Floating production units are gaining acceptance by the oil industry as alternatives to fixed platforms for deepwater applications. Many floating systems are already in operation, mostly converted semi-submersible drilling rigs and tankers. State-of-the-art installations include Shell's multiwell floating production, storage, and offloading system for Tunisia's Tazerka field in 460 feet which is tied-in to subsea wells. No systems of this type are currently available for use in water depths in excess of about 3,000 feet.

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[16] Dames & Moore, GMDI, and Belmar Engineering, "Deep Water Petroleum Exploration and Development in the California OCS," report prepared for the Minerals Management Service (January 1984).

[17] D. M. Coleman, "Offshore Storage, Tanker Loading, and Floating Facilities," Outer Continental Shelf Frontier Technology Symposium (1979); and "A Complete Producing System for Deep Water," Proceedings of the DOT Conference (1983).

Chapter 4

Federal Services and Regulation

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Chapter 4

Federal Services and Regulation

OVERVIEW

The oil and gas development process largely is controlled by private industry after leasing lands from the Federal Government. However, industry must adhere to the terms of the leases which include safety and environmental regulations and stipulations. There is, therefore, a significant Federal responsibility to develop effective environmental standards, establish safe practices, monitor development activities, inspect operations, enforce regulations, and provide backup for emergency situations. These are broadly defined as regulatory responsibilities.

In addition, the Federal Government performs a number of public services which can affect the pace, the cost, and the reliability of future offshore development. Some of these services are provided for multiple public uses and offshore development is just one of these. Satellite data collection and provision of navigation systems are examples. Other services may be provided to fulfill broad national needs. Basic and applied research that will add to general knowledge of ice mechanics, oceanography, and materials applications in the Arctic are examples.

The Federal Government is both a regulator (e.g., of personnel safety) and a facilitator (e.g., in providing environmental information) of offshore development. Key questions about these two Federal responsibilities are:

- Are present technology and institutional arrangements adequate for meeting Federal responsibilities?
- Is the level of Federal involvement in the development of Arctic and deepwater frontiers adequate?
- Does the present level of Federal activity in these areas adequately safeguard the public interest?
- Is the division between Federal and private efforts appropriate?

RESEARCH AND DEVELOPMENT

The level of difficulty and the technical complexity of offshore petroleum systems in Arctic or deepwater regions dictates the need for substantial research and development efforts by industry and government. Industry sponsors research directed at developing or improving cost-effective and environmentally safe oil production systems. The Federal Government sponsors research which may enable it to perform its regulatory or service functions and research which advances the state of the art and knowledge in materials, environmental conditions, and technology.

Federal Research Programs

Although no major Federal program is focused on long-range development of Outer Continental Shelf (OCS) deepwater or Arctic frontier technologies, some work of this type is sponsored by the Sea Grant Program. The lack of this type of research may be partly a result of the executive branch and petroleum industry views that such efforts are properly left to private companies rather than the government. However, several Federal agencies have direct or indirect missions which require research activities related to the development of offshore petroleum resources. These are the Department of the Interior (DOI), the National Oceanic and Atmospheric Administration (NOAA), the U.S. Coast Guard and the Maritime Administration (MarAd) of the Department of Transportation, and the Department of Energy (DOE). In addition, the Office of Naval Research (ONR), the National Science Foundation (NSF), and the U.S. Army support Arctic research efforts which have spin-offs or goals which are related to offshore petroleum work.

As the regulating agency for the development of offshore oil and gas, the Minerals Management Service (MMS) in DOI supports several technology research and environmental assessment programs. The most important offshore technology research effort is the the Technology Assessment and Research Program (TA&R). The TA&R Program is designed to meet the need for an independent Federal assessment of the status of offshore technology so that MMS operations personnel can carry out their "regulatory" or "inspection" activities. The program focuses on technologies pertaining to blowout prevention, verification of the integrity of structures and pipelines, and oil spill containment and cleanup.

The TA&R program supports the following MMS functions: safety and pollution inspection, enforcement actions, accident investigations, permit and plan approvals, and well control training requirements. Where technology gaps are identified, original research is performed. Studies are conducted by universities, private companies, and government laboratories. Each work task provides for technical dialog between investigators, the industry, and MMS operations personnel. These investigators are used as staff adjuncts who present their work to MMS operations personnel through a technology transfer network of working groups known as Operations Technology Assessment Committees located in regional OCS offices and in headquarters.

Projects are conducted wherever possible in advance of OCS leasing. The TA&R Program, together with the technology transfer network, also is used by MMS as the primary method for identifying the "best available and safest technologies," which industry is required by law to use. About one-third of the projects are assessments and two-thirds examine technology gaps. Although the program covers all Federal leasing areas, a major emphasis is on the Arctic and deepwater. About one-third of TA&R projects are participatory with the industry (see table 4-1).

The Outer Continental Shelf Environmental Assessment Program office of NOAA undertakes or manages much of the environmental data collection program under the MMS Environmental Studies Program. Additionally, the National Weather Service, a part of NOAA, collects and disseminates weather data, and NOAA participates with the U.S. Navy in the operation of the Joint Ice Center. NOAA also has recently announced a research project to study Arctic storms.

The DOE Arctic program has acted as a clearinghouse for government and industry technology research. In addition, technology programs have included sea ice engineering properties; geotechnology related to sediments and their interactions with ice and seismicity; and concept studies of the development of petroleum resources found below

Table 4-1.—Representative MMS-Sponsored Arctic and Deepwater Research Projects

Engineering properties of multiyear sea ice[a]
Ice forces against Arctic offshore platforms[a]
Reliability of concrete structures in the Arctic[a]
Assessment of ice accretion on offshore structures[a]
Fracture toughness of steel weldments for Arctic structures
Dynamic response of offshore structures due to waves and vortex shedding
Unmanned free-swimming undersea inspection technology[b]
Fluidic mud pulser for measurements while drilling systems
Acoustic transmission of digital data from underwater sensors
Control of blowout fires with water sprays
Subsea collection of oil from a blowing well
Demonstration of the capability of a robot inspection vehicle for the performance of useful work
Applications of risk analysis in offshore safety
Early detection of damage in offshore structures by a global ultrasonic inspection technique
Development of improved blowout prevention procedures for deepwater drilling operations[a]
Environmental cracking of high strength tension members in seawater[a]

[a] Joint project with industry.
[b] Joint project with another agency.

SOURCE: Minerals Management Service.

the ice canopy in deep Arctic waters. In the past, DOE sponsored a research program directed at long-range technology development, including a sizable drilling technology program. Some DOE drilling research is now carried out under the DOE geothermal program, and there may be spin-offs to petroleum drilling.

MarAd sponsors research related to the future of the U.S. shipping industry. In order to understand the problems of commercial ships in navigating the Arctic Ocean, MarAd has supported studies in ice navigation. Using Coast Guard icebreakers, trafficability studies have measured power requirements, the time required to navigate through ice-infested waters, and the forces imposed on ships by the ice. Funding for this work has been significantly reduced in recent years.

ONR traditionally has supported research in those disciplines which would provide the basis for the understanding of natural phenomena and which might be used in the development of new equipment or at-sea naval operations. Research information developed by ONR academic investigators is generally published in the scientific literature and thus available to the agencies and industries involved in Arctic energy resource development.

NSF supports a broad range of basic research addressing Arctic scientific problems. The NSF research grants that pertain to offshore areas include biological, oceanographic, geological/geophysical, glaciology, meteorology and atmospheric sciences, and engineering.

The U.S. Army Cold Regions Research and Engineering Laboratory is a specialty laboratory operated by the U.S. Army Corps of Engineers. The laboratory focuses on geophysics and engineering in the world's cold regions as these subjects relate to military operations and construction. The laboratory also possesses a large library that works in conjunction with the Library of Congress to access the world literature on the geophysics and engineering of the cold regions. The Army laboratory has a long and distinguished record of work on problems related to the science and engineering of the polar oceans. This has focused on problems caused by the presence of ice, ice islands and icebergs, snow cover, and subsea permafrost. Most research on polar ocean problems has been funded by other government agencies and private industry.

Photo credit: ARCTEC, Inc.

Model ice-breaking tanker (a scale replica of the SS Manhatten) being tested to measure force required for passage through first-year ice

Future Research and Development

It appears that industry's research and development needs will continue to be met in a timely manner without any significant changes in Federal policy or incentives. However, there are concerns related to the government's role in supporting and monitoring future research, maintaining national facilities, and supporting excellence in universities and other research institutions. Some have been concerned about the uncoordinated and fragmented nature of Federal programs, and suggestions have been made to consolidate or coordinate research through a joint industry/government/academic council.

Most industry spokesmen support the existing MMS research program which concentrates on matters directly related to that agency's regulatory role. However, they believe any expansion of this program may overlap with industry activities. Academic researchers generally maintain that the present government effort is not sufficient to assure adequate support for basic and advanced engineering research and to provide continuing support for education. Larger and longer term commitments may be needed to accomplish relevant basic research, to prepare academic institutions to better accommodate and address specific industry needs, and to ensure a steady supply of well-trained and talented scientists and engineers.

While cooperative industry research has produced hundreds of reports on critical subjects, very few of these have been made available to the public. Most research and data are kept confidential by the participants, but it could possibly be made public after a certain time period. There is generally a need to promote more cooperation between the Federal Government, industry, other public groups, and other governments in Arctic programs. Efficient data collection often requires coverage over territories of several nations (e.g., Canadian and Alaskan Beaufort Sea regions). Cooperative research with public groups could assist communication of the results and the implications of development options.

One of the greatest values of federally sponsored research is the ability of some agencies to design programs with multi-year continuity so that basic problems can be consistently studied and long-term data can be collected and applied. This is essential to an understanding of some basic phenomena such as ice movement and forces, meteorological, and oceanographic processes. It is, therefore, important to maintain continuity in many of the government-supported research efforts.

One approach to enhancing Federal research efforts is contained in the Arctic Research and Policy Act (ARPA) of 1984. The Act finds that Federal Arctic research is fragmented and uncoordinated and that a comprehensive policy and program to organize and fund Arctic scientific research is necessary to fulfill national objectives. National Arctic objectives specifically cited in the bill, which require or would benefit from a more comprehensive scientific research effort, include development of the living and nonliving resources of the Arctic, environmental protection, national security, mitigation of the adverse consequences of development to Arctic residents, and better understanding of global weather patterns.

ARPA creates two new institutions—the Arctic Research Commission and the Interagency Arctic Research Policy Committee—to carry out the purposes of the Act. The Interagency Arctic Research Policy Committee is composed of representatives of all Federal agencies with responsibilities in the Arctic. The National Science Foundation chairs the Committee and is responsible for ensuring the implementation of national Arctic research policy. ARPA calls for a 5-year implementation plan, which, at a minimum, must assess national needs and problems regarding the Arctic and the research necessary to address those needs and problems. The Arctic Research Commission is, in essence, an independent advisory board. The Commission is responsible for: developing and recommending an integrated national research policy; facilitating cooperation among Federal, State, and local governments; and assisting in developing the 5-year plan.

However, ARPA provides no additional funding for Arctic research. Moreover, although the law urges agency coordination and integration of research programs, there is no authority in the bill to direct departmental budgeting. Therefore, departments will continue to set their own research priorities based on agency-specific missions. Without research funds and with authority limited to giving advice and making recommendations, the Commission's present duties are limited. However, both the 5-year implementation plan and the survey of Arctic research that the Interagency Committee will conduct will be useful if they help coordinate the overall Federal Arctic research effort.

FEDERAL SERVICES

Environmental Information

Firms engaged in offshore oil and gas development require a great deal of technical environmental information—information about weather, ice, oceanographic conditions, soil mechanics, and seismicity—for the design and operation of offshore structures and supporting systems.

The offshore industry receives information on these conditions from both Federal and private sources, and many firms collect their own data as well. Federal environmental data services are designed to serve the public at large, broad sectors of the economy, and the needs of other Federal agencies. Such information is used by the offshore petroleum industry to gain information on global, regional, and local conditions over both short and long timeframes. There is no charge for most Federal forecast or operational data products. However, charges are assessed for some products that have more identifiable users (e.g., for provision of LANDSAT images), and often users must pay for the communications devices (e.g., dedicated phone lines) used to access information.

The main Federal agencies involved in collecting, processing, and disseminating offshore environmental information are NOAA, Navy, the National Aeronautics and Space Administration (NASA), and the Air Force. NOAA is the primary point of contact between civilian users and Federal agencies. Principal NOAA units are the National Weather Service; National Environmental Satellite, Data, and Information Service; and the National Ocean Service. The Navy/NOAA Joint Ice Center plays a key role in disseminating ice charts and other ice-related information. NOAA has several units involved in maintaining and improving user services, notably two Ocean Service Centers in Anchorage, Alaska and Seattle, Washington.

Most data used by Federal agencies come from federally operated satellites, ships, and other systems. However, agencies also incorporate data from private sources. Site-specific information used by firms developing oil and gas resources is usually obtained from private firms, including the firms contracted to conduct actual operations. For example, operators in an area affected by ice movements may supplement information received from Federal agencies with direct observations from company supply vessels or helicopters.

"Value-added" private firms take historical and/or forecast data from Federal sources, refine it by additional processing and interpretation, and often supplement it by additional observations. Such firms tailor products to specific user needs, giving forecasts with greater frequency and more geographic specificity than usually can be obtained from Federal agencies.

Information Needs

There are some problems with the current provision of offshore environmental information. Voids exist in historical and near real-time data. There is less information available about some types of environmental conditions and some offshore regions. Greater precision and accuracy are needed in describing and forecasting conditions. For some activities, the environmental information available may be insufficiently precise. Many users desire greater accuracy and better spatial resolution in the observations and forecasts. In addition, products may be too infrequent. Some users suggest that the time intervals between measurements of conditions, and between measurements and delivery of information to users, should be shortened. The need for more accurate, longer range forecasts has also been stressed.[1]

Data are lacking for a variety of reasons. For example, the sensors mounted on current NOAA satellites are impeded by clouds, fogs, blowing snow, and in the case of sensors restricted to the visible spectrum, darkness. Outside of well-traveled ocean routes and populated coastal areas, data to supplement satellite observations are limited. Minimal archived data are available for use in "hindcasting" conditions. Much of the satellite data which could be available are not collected and that collected are usually not archived because of either a lack of funds or the absence of a specific program to do so.

Nontechnical problems also affect the performance of Federal agencies. Many NOAA programs have been targeted for reduction and may find it difficult to cope with the increases in user demands likely to occur with the expansion of Arctic development. Suggestions have also been made that the Federal Government establish a single focal point for collecting, evaluating, and disseminating environmental data.

An OTA survey showed that improvements may be needed in many information areas for pre-lease sale planning and, to an even greater extent, for site development. Types of information most frequently mentioned as needing improvements are: ice-related information in the Chukchi and Beaufort Seas, and to a lesser extent, the northern Bering and Norton Sound; soil geotechnical properties in every offshore area; permafrost in the Chukchi and Beaufort; storm surges in the Chukchi and northern Bering; wave climatology in the Chukchi and, to a lesser extent, the Bering; currents in the Chukchi; and wind velocity and visibility in the northern Bering, and bathymetry, to a lesser extent, in all areas. Information about air temperature, precipitation, and tides was generally seen as being satisfactory or not requiring major improvement.

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[1] National Advisory Committee on Oceans and Atmosphere, "Ocean Services for the Nation" (January 1981).

Better data about environmental conditions could result in financial savings and improve the safety of offshore operations. Lack of information about environmental conditions may cause overdesign of drilling platforms and ships. Better information could reduce a portion of the costs associated with overly conservative design.

Several rigs have been lost to severe storms in non-Arctic areas, at a cost of scores of lives and tens of millions of dollars, and oil spills have resulted from ship accidents. While human error has often been a contributing factor, better information about storms could help prevent recurrences of these events.

Operations are planned and carried out on the expectation of suitable weather, ice, and ocean conditions. Adverse environmental conditions often cause offshore operations to be suspended. When expensive pieces of equipment and their supporting systems are laid up due to unforeseen changes in environmental conditions, additional expenses quickly accumulate. For example, lease costs for semi-submersibles can exceed $50,000 per day, with weather-related losses of over $1 million per rig per year not uncommon. Similarly, many days are lost for resupply operations due to weather conditions. It is possible that better information could reduce such losses.[2]

More efficient ship routing, based on better information, could also result in large savings in time at sea, and associated costs in fuel, damage to cargo, and other items.

Photo credit: Gulf Oil Corp.

A great deal must be known about ice forces to allow safe Arctic operations

Future Information Services

Federal agencies are undertaking several initiatives that may improve environmental information services. For example, the NOAA Ocean Service Center concept appears particularly promising as a way to improve contacts with users of NOAA services. Several technological improvements also are important, including new sensors scheduled to be placed on future satellites. These advances, especially new satellite systems, could substantially reduce data gaps. New Navy oceanographic and Air Force meteorologic satellites will penetrate cloud cover and other low visibility conditions with microwave sensors.

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[2] Jet Propulsion Laboratory, "Ocean Services User Needs Assessment" (Apr. 5, 1984), pp. 4-29.

For extremely high resolution, synthetic aperature radar (SAR) imagery is needed. No U.S. satellite is scheduled to carry a SAR during this decade. However, planned European Space Agency (ESA), Canadian, and Japanese satellites are scheduled to have SARs. NASA has proposed to establish a SAR receiving station in Alaska to collect data on offshore Alaskan areas from the ESA satellite ERS-1, and NOAA has expressed interest in disseminating and perhaps processing such data. Acquisition of SAR data would greatly improve existing information on sea ice, and the offshore industry has gone on record in support of the proposed NASA receiving station and associated data processing capability. However, some uncertainties remain about acquiring the ERS-1 SAR data. Funding for the NASA and NOAA initiatives to handle such data have not yet been approved. It is also uncertain whether ERS-1 will be launched on time, and whether its sensors will be switched on while it is flying over Alaska.

It is equally uncertain whether operational products and real-time data would be provided as a result of accessing the ERS-1 SAR data. The offshore industry wants processed images made available to forecasters or industrial users within hours of data acquisition. Current NASA plans are to process data several days after acquisition. Near real-time dissemination of data would require additional processing capacity, and NASA does not see its function as including provision of operational products or real-time data. However, companies surveyed by the Jet Propulsion Laboratory at the California Institute of Technology expressed a willingness to contribute to a NOAA-sponsored pilot program to develop real-time SAR data dissemination, depending on the results of further study.

Another uncertainty lies in Administration plans for funding reductions for meteorological satellites from two polar orbiters to one. According to NOAA, a one-polar-satellite system would meet the core of U.S. weather forecasting requirements. However, the frequency with which any one area would be covered would be reduced from once every 6 hours to once every 12 hours. Reduction of frequency would have significant effects on prediction of weather affecting Alaska, Hawaii, and other Pacific territories, and on activities using satellite data services. This would be especially true in areas poorly covered by nonsatellite information gathering systems, including most of the offshore frontier areas. In addition, the amount of information shared with other countries would be reduced, potentially affecting reciprocal information exchanges.

In addition, the Administration is seeking to increase the role of the private sector in supplying environmental information services. In March 1983, the Administration endorsed the transfer of nondefense remote sensing satellite systems—LANDSAT, civilian weather satellites, and any future ocean sensing satellites—to the private sector. Weather services and, to a lesser extent, future ocean sensing services are considered by many people to be public goods, appropriate for the Federal Government to provide, even if at a loss. Congressional concern culminated in an authorization bill signed into law prohibiting the sale of the weather satellite system to the private sector. Plans for the sale of LANDSAT have continued, however, and legislation to transfer LANDSAT to the private sector was enacted in July 1984 (Public Law 98-365). Industries involved in offshore oil and gas development fear that nongovernmental managers of LANDSAT may not devote adequate resources to further develop remote sensing technology and that costs may greatly increase.[3]

Current NOAA plans are to transfer a portion of its nautical chart-making to the private sector. As with satellite commercialization, the Administration sees advantages in reducing the Federal role in an area where the private sector could take over operations. Critics have argued that safety could be reduced if fewer charts were made or if people were reluctant to purchase updated charts because of increased charges. There is also concern about Federal liability in marine casualty cases.

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[3] U.S. Congress, Office of Technology Assessment "Remote Sensing and the Private Sector: Issues for Discussion—A Technical Memorandum" (Washington, DC: U.S. Government Printing Office, March 1984).

Navigation Services

Federal agencies operate ground stations and satellite platforms that beam radio transmissions used to navigate and to position vessels and structures. Such transmissions are vital to many offshore operations, such as vessel positioning for seismic surveys, positioning of platforms, pipeline laying, and tanker transport. Radio aids provide a high level of accuracy, combined with broad coverage. They are especially important in situations where visibility is reduced. Arctic operations in particular are, or will be, dependent on radio aids. This is because Arctic waters are relatively poorly charted and contain many hazards, short-range aids such as buoys are often difficult to maintain in Arctic waters, and visibility is reduced in many areas by extended darkness and frequent storms or fog.[4]

This section covers only those navigation services which are known as "radiodetermination." This encompasses both radionavigation and radiolocation, or positioning for purposes other than navigation. Federal agencies usually use the term "radionavigation" when describing Federal services in this area. While Federal radio systems are used by the civil sector for uses going beyond navigation, the statutory responsibility of Federal agencies only extends to providing a level of service that is sufficient for safe and efficient navigation. Radiolocation or positioning generally requires more precise data.

Federal Radionavigation Systems

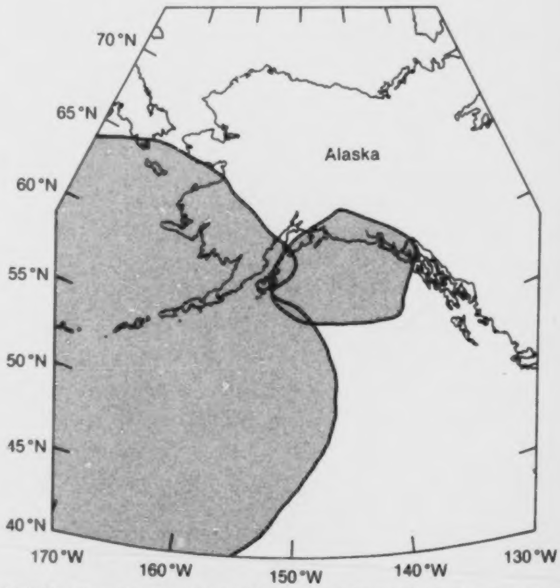
Offshore operators commonly use their own shore-based portable positioning systems or contract with private companies for such systems during seismic exploration and for rig positioning, where high accuracy is needed. For many purposes, however, systems operated by the U.S. Coast Guard, Navy, and Air Force are vital to offshore exploration, production, and transportation of oil and gas.

The Coast Guard operates two types of long-range radio aids, LORAN-C and OMEGA. LORAN-C operates by measuring differences in the time of receipt between radio pulses from transmitters several hundred miles from each other. The usable range of LORAN-C is up to 1,500 miles, depending on system configuration. Worldwide, there are 43 U.S.-operated LORAN-C stations. While Alaskan waters up into the Bering Sea are covered by LORAN-C, waters north of Point Clarence either are not covered or coverage is subject to interference (see figure 4-1). At the present time, there are no plans to extend LORAN-C coverage to Arctic regions not currently served.

OMEGA is a radionavigation system similar to LORAN-C, operating at lower frequencies. It has greater range, covering the entire world, but its accuracy is less: 2 to 4 nautical miles for predictable and repeatable accuracy. Eight stations, two of which are in the United States, comprise the OMEGA system.[5]

The Navy operates a satellite system called TRANSIT, with the Coast Guard as the point of contact for civilian users. More than 90 percent of users of TRANSIT are civilians. The TRANSIT

Figure 4-1.—Loran-C Coverage of Alaska



SOURCE: Transportation Systems Center, "Benefits and Costs of Loran-C Expansion Alternatives in Alaska," April 1983.

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[4] Maritime Transportation Research Board, "Maritime Services to Support Polar Resource Development" (Washington, DC: National Academy Press, 1981).

[5] Nevin A. Pealer, "Federal Radionavigation Planning," *Proceedings of the National Technical Meeting of the Institute of Navigation* (January 1984).

system has five satellites in polar orbit, with worldwide coverage. The limited number of satellites in the TRANSIT system means that, depending on their location, users experience gaps lasting from 30 minutes to several hours in the reception of transmissions. Transmission gaps are greatest at the equator, less at northern latitudes.

Present Federal plans are for LORAN-C, OMEGA, and TRANSIT to be phased out and eventually replaced by the Global Positioning System (GPS), which is to be operated by the Air Force. As with TRANSIT, the Coast Guard is to be the contact agency for civilian uses of GPS. When fully developed, the GPS will use 18 satellites, with three operating spares also in orbit. GPS is intended to provide highly accurate, continuous, worldwide positioning information for weapons delivery systems; however, it also will be used by civilians for nonmilitary purposes.

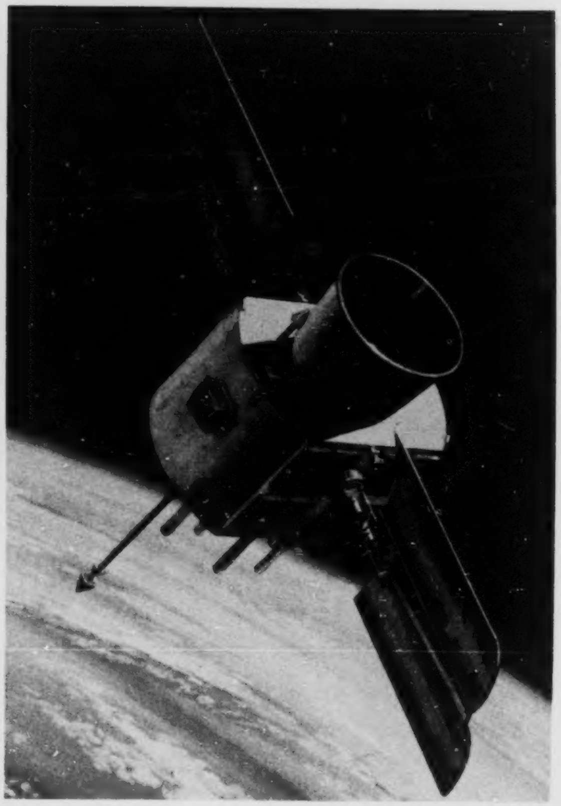

Photo credit: Rockwell International

The Global Positioning System (GPS) will provide radionavigation services for Arctic operators

GPS is currently in a research/demonstration phase. Some test satellites have been launched and used to verify the GPS concept. Launches of the satellites that will establish the operational system are scheduled to begin in late 1986. By 1987 or 1988, two-dimensional coverage suitable for marine operations should be achieved, with full three-dimensional coverage suitable for aircraft available by late 1988 or early 1989. TRANSIT is to be terminated in 1994, or as soon as the military can change over to GPS, which is expected to be complete by the early 1990s. Although termination dates for LORAN-C and OMEGA have not been fixed, suggested dates range from soon after 1994 to beyond 2000. The Coast Guard favors continuation of LORAN-C at least until 2000. Foreign LORAN-C stations could continue to operate for some time after domestic U.S. stations are terminated, depending on foreign governmental support.

The European Space Agency (ESA) is conducting studies on the feasibility of a 24-satellite civilian navigation system called NAVSAT. Funding may come from indirect charges, rather than through direct user charges. NAVSAT may have advantages over GPS in that it would be a civilian-oriented system, whereas GPS is primarily a military system. The timeframe for development of NAVSAT is not clear. In addition, the Soviet Union is developing a satellite navigation system called GLONASS that will be similar to GPS. It is not clear when GLONASS will become fully operational. Although initially intended for use by Soviet civil aviation and special-purpose ocean vessels, GLONASS may eventually be offered for worldwide use free of charge.

Radionavigation Needs

Different radiodetermination tasks require different levels of accuracy. For example, seismic surveys require extremely high repeatable accuracy levels. Vessel navigation generally requires less accurate satellite data. OMEGA is adequate for ocean navigation, especially away from the coastal zone, but for other purposes does not provide sufficient accuracy. LORAN-C gives greater accuracy, and the continuous broadcasts of LORAN-C are an important asset. LORAN-C capabilities are sufficient for most coastal navigation. A major drawback of LORAN-C is its lack of coverage of northern Alaskan waters. LORAN-C and other nonsatellite systems are also more susceptible to atmospheric interference. TRANSIT provides greater accuracy than LORAN-C, but its usefulness is lowered by gaps in transmissions.

Whether or not current radiodetermination systems should be upgraded depends largely on evaluation of the prospects for GPS. Concerns have emerged regarding GPS agency/user relations, the accuracy of GPS information provided to civilian users, the timing of the phase-in of the system, and costs and charges to users.

If TRANSIT were phased out before GPS were made available, the overall level of Federal service would be lowered. Many users seek assurances that GPS will provide services comparable to existing systems, and that other systems will continue to operate until GPS provides such levels of service. The offshore industry believes that GPS user charges are acceptable in principle, but that such charges should be "equitably" assessed. Industry groups have opposed plans that would favor recreational boaters or fishermen.

Icebreaking

Alaskan Arctic waters are ice-covered or experience significant ice concentrations for all or part of the year. Specialized vessels that can operate in ice-infested waters will be needed if development is to proceed. Possible missions performed by icebreaking or ice-capable vessels related to oil and gas operations include opening of shipping lanes and drilling vessel sites, protection of drilling operations against drifting ice, supply of operations, pollution response, search and rescue, and transport of petroleum products. In U.S. waters, missions such as supply operations and transport of products are private sector responsibilities. Missions such as pollution response and search and rescue are undertaken by both private and Federal units. The Coast Guard also carries out vessel-towing and other rescue and safety-related missions.

The need for icebreakers will vary with the location of oil and gas fields, their size, and their distribution. Because it is difficult to project what the conditions of oil and gas development will be, projections of future icebreaker needs are uncertain. If fields are close to shore, use of pipelines, aircraft, hovercraft, and land transport over ice would minimize the need for icebreakers. However, in many situations, especially for remote fields, it may be advantageous to use icebreakers. For example, air operations tend to be far more expensive than ship operations, especially for supply tasks involving large volumes. In addition, helicopter range is limited, and aircraft are more limited than ships by weather conditions.

Federal Icebreaking Services

With the transfer of Navy icebreaking functions to the Coast Guard in 1965, the Coast Guard became the sole Federal agency to operate icebreakers. Apart from its own missions, such as enforcement of laws and treaties, the Coast Guard also provides icebreaking support to other Federal agencies for such purposes as scientific observation and supply of installations. In the early 1980s, Coast Guard polar icebreakers spent an average of 127 days per year in the United States and western Canadian Arctic.[6]

The Coast Guard currently maintains five polar icebreakers (see table 4-2). In terms of numbers, the Coast Guard icebreaking fleet ranks third in the world, behind the Soviet and Canadian fleets (see table 4-3). Private icebreaking services are available in some U.S. Arctic areas. For example, tugboat-pushed barges supply North Slope oil operations, breaking ice each year from August until October.

However, some believe that the Coast Guard has barely adequate resources to undertake current operations and would have inadequate resources to carry out the expanded duties brought about by increased oil and gas development in the Arctic. Apart from the two Polar class ships, the Federal icebreaking fleet is in fair to poor condition (see table 4-4). The U.S. polar icebreaking fleet is one of the the world's oldest, with a median age of about 30 years. Two of the four original Wind class vessels were retired several years ago, and the other two still in service have poor crew facilities and defi-

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[6] U.S. Coast Guard, "United States Polar Icebreaker Requirements Study" (July 1984), p. A-11.

Table 4-2.—Coast Guard Polar Icebreakers

Icebreaker	Year built	Length (ft)	Displacement (long tons)	Shaft horsepower	Icebreaking capability: continuous/ (ft)	ramming (ft)	Complement	Homeport
Westwind	1944	269	6,260	10,000	3	11	181	Mobile, AL
Northwind	1945	269	6,260	10,000	3	11	181	Wilmington, NC
Glacier	1955	310	8,678	21,000	4	14.5	280	Long Beach, CA[a]
Polar Star	1976	399	12,688	60,000	6	21	164	Seattle, WA
Polar Sea	1978	399	12,688	60,000	6	21	164	Seattle, WA

[a] To be moved to Seattle, spring 1985.

SOURCE: U.S. Coast Guard.

Table 4-3.—Comparative Government Polar Icebreaker Figures

Nation	Vessel/class	Built	Length (ft)	Draft (ft)	Displacment (tons)	Shaft horsepower	Power[a] plant	Icebreaking[b] capability (ft)
U.S.S.R.	Leonid Brezhnev	1975	446	36	25,000	75,000	N	8
	Sibir	1977						
	Rossiya	1985						
U.S.S.R.	Lenin	1959	439	34	19,240	44,000	N	7
U.S.A.	Polar Star	1976	399	31	13,000	60,000 or	GT or	6+
	Polar Sea	1978				18,000	DE	
U.S.S.R.	Yermak class . . . . (3 ships)	1974-76	442	36	20,241	36,000	DE	6
Japan	Shirase	1982	440	30	17,600	30,000	DE	5
Canada	Louis St. Laurent	1969	366	31	14,000	24,000	TE	4-5
Canada (private)	Kalvik class . . . . (2 ships)	1983	289	26	7,000	23,200	GD	5
U.S.S.R.	Moskva class . . . . (5 ships)	1959-69	400	31	15,360	22,000	DE	4.5
U.S.S.R.	Kapitan Dranitsyn . . . . . class (2 ships)	1980-81	433	28	14,900	22,000	DE	4.5
U.S.S.R.	Kapitan Sorokin . . . . class (2 ships)	1977-78	433	28	14,900	22,000	DE	4.5
Canada (private)	Canimar Kigoriak	1979	299	28	6,500	16,360	GD	4-5
USA	Glacier	1955	310	28	8,000	21,000	DE	3.5
Canada	MacDonald	1960	315	28	9,160	15,000	DE	3.5
Canada	Radisson class . . . . (3 ships)	1978-82	316	24	8,055	13,600	DE	3.5
Argentina	Almirante Irizar	1978	391	31	14,500	16,200	DE	3.5
Canada (private)	Ikaluk class . . . . (2 ships)	1983	258	25	6,000	14,900	GD	3-4
W. Germany	Polarstern	1982	387	35	14,800	20,000	GD	3
Japan	Fuji	1965	328	29	8,566	12,000	DE	3
Canada (private)	Robert Lemeur	1982	272	18	6,512	9,000	GD	3-4
Canada	Labrador	1953	290	30	7,000	10,000	DE	3
USA	Northwind . . . . Westwind	1944-45	269	28	7,000	10,000	DE	3

[a] Power plants: N = nuclear; GT = gas turbine; DE = diesel electric; TE = turbo-electric; GD = geared diesel.

[b] Estimated continuous, level icebreaking capability at 3 knots.

[c] This table does not include some 56 vessels (subarctic icebreakers) that are capable of icebreaking operations in seasonally ice-covered coastal seas and lakes outside the polar regions. These ships are owned by Canada (2), Denmark (2), Finland (9), W. Germany (1), Sweden (6), USA (1-Mackinaw), U.S.S.R. (34), and E. Germany (1).

[d] All government-owned icebreakers except for those Canadian vessels noted as private.

SOURCE: U.S. Coast Guard.

Table 4-4.—Condition of Coast Guard Icebreaking Fleet

	Icebreaker type		
Category	Wind class	Glacier	Polar class
Prime mission equipment/ science facilities	2	3	3
Habitability	1	2	5
Hull and ship structure	1	3	5
Main propulsion	4	3	4
Auxiliary	1	3	4
Command and control	2	4	4

5 = excellent; 4 = good; 3 = fair; 2 = poor; 1 = inadequate.

SOURCE: U.S. Coast Guard.

ciencies in steering and firefighting systems. These older icebreakers are considered by the Coast Guard to be nearing the end of their ability to provide reliable service. Their active service is projected to end in the late 1980s.

The Coast Guard currently assumes that it will continue to have an icebreaker fleet of five ships, although it is possible that a four ship system will be adopted. Because of the long lead-times involved in the design, construction, and testing of icebreakers—about 5 to 8 years—decisions must be made soon concerning the number of icebreakers desired and their characteristics (size, draft, propulsion systems, equipment, etc.). Congress has authorized the construction of at least two new Polar class icebreakers by the end of fiscal year 1990.

Future Icebreaking Needs

Offshore developments in Arctic regions may require icebreaker support for much of the year. Different levels of service could be provided by the Coast Guard. The Coast Guard believes that the continuous presence of Coast Guard icebreakers is not required in the Arctic at this time; rather, it seeks to maintain the ability to enter Arctic waters and perform required missions. If a continuous presence were needed, different icebreaker design and/or more northern icebreaker basing would be required.

Photo credit: U.S. Coast Guard

Coast Guard Icebreaker Polar Sea

The most capable icebreakers in the Coast Guard fleet, the Polar Star and the Polar Sea, are capable of transiting continuously through over 6 feet of first-year ice at 3 knots, without backing and ramming. They can break through ice thicknesses of 21 feet by backing and ramming. There is some disagreement regarding the adequacy of these ships for operations in all Arctic winter conditions. The Coast Guard believes that the Polar class vessels have sufficient characteristics, while some other sources believe that far more powerful icebreakers are needed. If many operations take place in the Beaufort and Chukchi Seas, as opposed to the Bering, icebreakers will have to meet more rigorous requirements. The Coast Guard is currently deciding the class of future polar icebreakers.

A problem for year-round service is the endurance of icebreakers. The gas turbine engines on the Polar class vessels, used for heavy icebreaking, consume large amounts of fuel and require relatively frequent refueling. Even in conditions where diesel electric engines are used, icebreakers that have long traveling times to reach Arctic duty experience endurance problems. The home bases of the polar fleet are Seattle, Long Beach, Mobile, and Wilmington, with two (soon to be three) of the five polar icebreakers based in Seattle. From Seattle to the North Slope is at least a 2-week voyage. Currently, there are no refueling stations north of the Aleutians. If a more substantial Coast Guard icebreaking presence were to be established, vessels with greater endurance would be needed or refueling and other support facilities would have to be constructed closer to offshore operations. One problem with northern basing is that the closer the operations base is to the Arctic, the farther away it would be from Antarctica, where many missions are carried out. It is also thought that ship maintenance would be more difficult if northern bases were used. The Coast Guard has no present plans to establish northern basing for icebreakers.

Some Arctic areas such as the eastern Beaufort are relatively shallow for long distances offshore and shallow draft icebreaking capability may be needed. Such icebreakers must be able to operate in less than 20-foot water depths and to break ice continuously 2 to 3 feet thick.[7] The Coast Guard currently lacks vessels that combine sufficient strength to transit through Arctic ice with shallow enough drafts to come close to shore. The new generation of Polar icebreakers planned for purchase by the Coast Guard will also be deep-draft. The Coast Guard is waiting to see what level of commitment industry will be making to offshore exploration before deciding what type of shallow-draft icebreaking service may be needed.

Icebreakers are expensive to build and operate. Total annual costs of operating four to five icebreakers under various alternatives range from $35 to $50 million. Icebreakers support the missions of a number of agencies besides the Coast Guard, especially the Department of Defense and the National Science Foundation. Participating agencies and groups pay a proportionate share of Coast Guard expenses incurred on icebreaking missions, including pay, maintenance, and fuel costs. Because Coast Guard icebreaking is dependent on the year-to-year operational plans of several agencies, Coast Guard planners face considerable uncertainty. If a single agency decides not to utilize icebreaking services, the Coast Guard may have to withdraw a ship from service. The Coast Guard is currently seeking a revision of the cost-sharing system.

There are also questions about the extent to which icebreaking services should be provided to private firms developing offshore oil and gas. Icebreaking could be a private sector activity, with icebreakers owned and operated by private firms. Or the government could be reimbursed by the offshore oil and gas industry for all or part of its services.

No Federal icebreaking assistance is provided routinely to North Slope commercial operations. The position of the Coast Guard is that responsibility for routine icebreaking for marine commerce rests primarily with the marine industry and not with the Federal Government. However, if available commercial icebreaking services are inadequate, the Coast Guard will provide icebreaking assistance. Decisions on the availability and adequacy of commercial services are made by Coast Guard District Commanders.

There is a need for the Coast Guard to continue icebreaking services in support of such statutory mandated missions as search and rescue, emergency response, enforcement of laws and treaties,

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[7] Lawson W. Brigham, "Future U.S. Coast Guard Shallow-Draft Icebreaker Requirements in Alaska," *Proceedings of the Symposium on Science and Arctic Hydrocarbon Exploration: The Beaufort Experience* (September 1983).

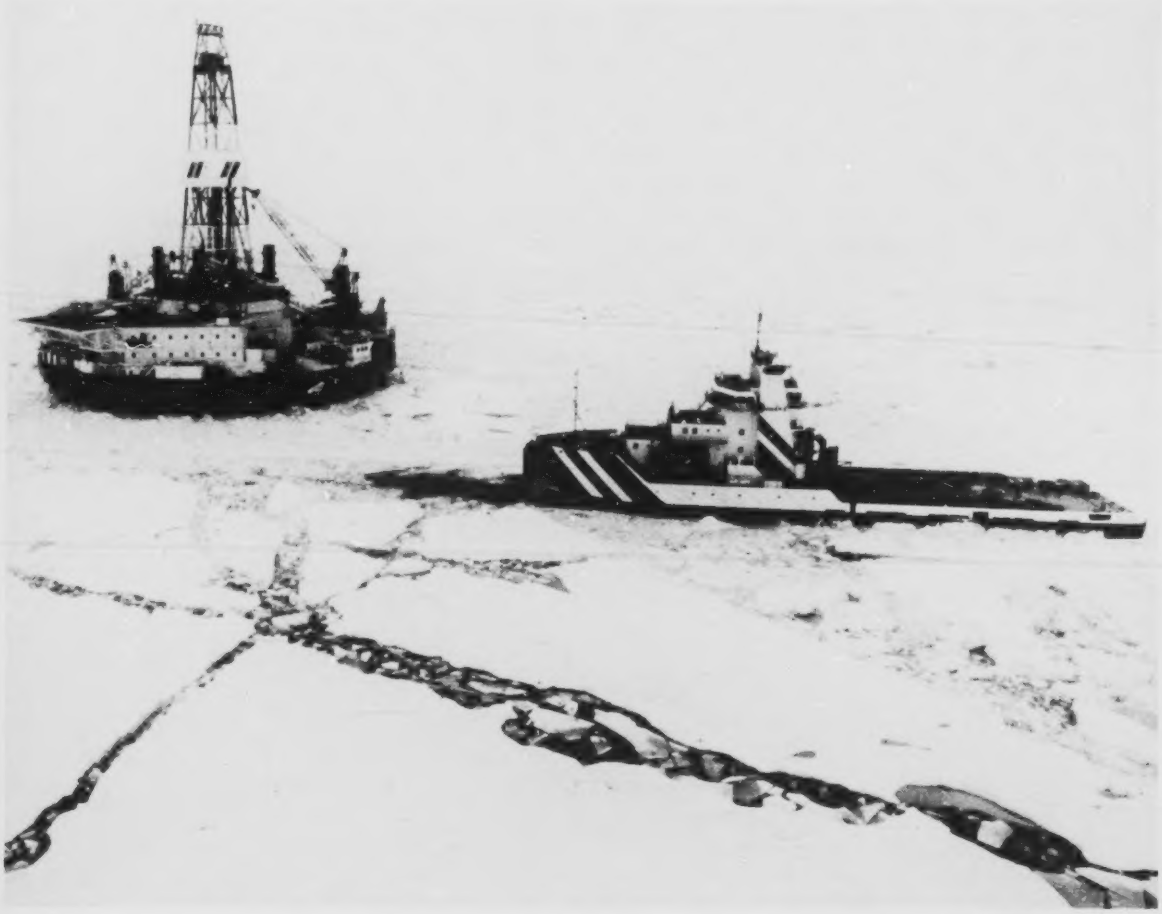

Photo credit: Gulf Canada

Floating conically-shaped mobile drilling unit "Kulluk" operating in the Canadian Beaufort Sea with icebreaker support

and pollution response. However, private operators feel that they can provide the offshore oil and gas industry icebreaking services such as supply and channel breaking. At the present time, there are few U.S. private sector icebreakers, and current capabilities are limited to the summer months. As oil and gas development proceeds, these capabilities may expand. The Coast Guard would probably still be called upon for icebreaking support in emergency ice conditions.

There are incentives for industry to provide its own icebreaking or contract with private firms for icebreaking services to support oil and gas development. Special Coast Guard requirements for larger ships increase the cost of Federal icebreakers and icebreaking services in comparison with private services and would add to any Federal user fees. Also, without the need to design and operate vessels for the multi-mission roles that Coast Guard vessels must fulfill, private sector icebreaking vessels could be tailored to meet industry missions.[8]

In general, private icebreaking firms have been strong supporters of user fees, believing that they could not compete against taxpayer-subsidized Coast Guard services. The Coast Guard advocates assessing any user fees only for activities beyond the statutory responsibilities of the Coast Guard. Coast Guard policy for the Arctic is not clearly established and may not be until there is increased oil and gas development. A 1982 interagency study declared that "although Arctic petroleum development could be argued to be in the national interest, the services of Coast Guard icebreakers to facilitate commerce could be argued on the other hand to be a free subsidy to the petroluem industry. Presently there are no plans for Coast Guard icebreakers to be used to directly support petroleum exploitation and commerce. If such support were provided, it would be appropriate for user fees."[9]

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[8] National Petroleum Council, *U.S. Arctic Oil and Gas*, Working Paper-26 (December 1981), pp. IV 52-54.

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[9] Department of Transportation, "Coast Guard Roles and Missions" (March 1982), p. 157.

SAFETY

Offshore oil and gas operations entail hard and dangerous work. Special risks are presented in frontier regions because of harsh environments and remote locations. Offshore operators have made substantial efforts to safeguard health and safety, and the safety record of offshore operations appears equal to or better than the record of comparable onshore industries. Still, there is a need for continuing attention to ways in which the Federal Government can assist in preventing work-related injuries and fatalities.

As in other industrial sectors, offshore employers vary greatly in their safety records. Industry associations and many employers have strongly promoted safety, e.g., through sponsoring training of personnel, while other employers have been more lax. Public concerns about offshore operations have been stimulated by incidents that resulted in the death of a large number of workers. The best known of these incidents are the sinkings of the converted floating hotel Alexander Kielland (North Sea 1980, 123 fatalities), the Ocean Ranger (Eastern Canada 1982, 84 fatalities), and the drill ship Glomar Java Sea (South China Sea 1983, 81 fatalities). The last two were U.S. flag casualties. Offshore incidents in 1984 included a fire on the Enchova Central Platform off Brazil with 41 fatalities, and a natural gas explosion that killed 4 on the Zapata Lexington Number 26 semi-submersible rig in the Gulf of Mexico.

Offshore hazards can be categorized in different ways. A Marine Board report separates hazards according to the *type* of offshore activity: construction, drilling and well maintenance, production, and transportation.[10] Exploratory drilling is often considered to be the most hazardous phase of offshore operations, perhaps because less is known at that stage about formation characteristics. Only about one-fifth of all offshore employees are engaged in drilling; however, they experience a disproportionately larger number of accidents.

Accidents can also be categorized according to the *facility* where they occur: tankers, fixed platforms, mobile rigs, and support vessels and structures.[11]

Another division emphasizes the *scale* of accidents. There are individual accidents, such as falls, being struck by objects, and being pinned between objects. There are also occupational health problems separate from accidents, such as hearing loss due to machinery noise. Then, there are larger scale, catastrophic incidents, such as rig sinkings. Catastrophic incidents have occurred because of storms, structural failures, and capsizings. Other fatalities have resulted from well blowouts, explosions, and fires. Unlike most onshore occupations, offshore jobs pose hazards to off-duty workers, who often remain in close proximity to the work-site. Multiple fatalities and injuries also have resulted from transportation accidents involving helicopters and supply vessels.

This section focuses on several potential safety problems present in frontier regions. In general,

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[10] Marine Board, *Safety and Offshore Oil* (Washington, DC: National Academy Press, 1981), pp. 142-143.

[11] MITRE Corp., *Health and Environmental Effects of Oil and Gas Technologies: Research Needs* (July 1981), p. viii.

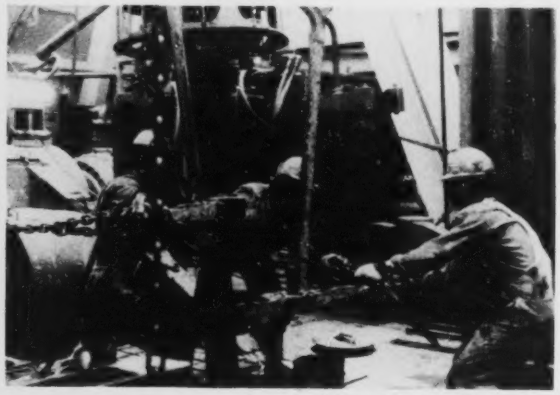

Photo credit: Peter Johnson, OTA

Roughnecks on the drilling rig floor at Shell's Seal Island discovery in the Beaufort Sea

the same types of offshore operational hazards are present no matter where operations take place, from the day-to-day dangers of working with machinery in confined spaces to unusual events such as evacuation under storm conditions. The high levels of investment required in frontier areas and the involvement of larger companies with relatively well-organized health and safety programs may make the future safety record of operations in such areas comparable to operations in more benign regions. Still, other things being equal, frontier conditions compound operational risks.

The environmental conditions in offshore frontier areas—extreme cold, ice, extended periods of darkness, blizzards and fog in the Arctic and severe storm conditions in the sub-Arctic and many deepwater areas—increase the dangers of operations. The remote location of many rigs in frontier areas makes evacuation of personnel more time-consuming and difficult, and delays medical treatment. The cold temperatures found in the Arctic and other northern regions are hazardous both in their direct effects on human health and in their reduction of worker efficiency. Although employees usually work in heated areas, at times they are exposed to cold. Human ability to perform tasks (e.g., in terms of reaction time) declines with decreasing temperature.[12] Bulky protective clothing worn for warmth may interfere with tasks in ways that cause injury risks to increase.

In situations where quick rescue is impossible, exposure suits are essential to survival in cold water. The time it takes for severe hypothermia and subsequent death to occur varies with such factors as water temperature, the weight and physical condition of the person in the water (thinner people suffer quicker heat loss), the type of clothing they are wearing (heavier clothing provides greater insulation), and the person's behavior (e.g., curling up in a fetal position decreases the rate of heat loss). Without an immersion suit, even a heavily clothed person in good physical condition can survive for only a few hours in winter seas. More lightly clothed people die from hypothermia in much less time. With a suit, survival time is increased many-fold. A major factor contributing to the deaths resulting from the Ocean Ranger disaster was the lack of exposure suits on board. Within a few minutes of entering the water, personnel were too numb to grasp life ropes and rings thrown to them from the rescue vessel. A Coast Guard rule went into effect in August 1984 requiring exposure suits for personnel on mobile offshore drilling units, among other types of vessels, that are located in specific offshore areas.

Injury and Fatality Statistics

There is currently no single comprehensive source of statistics on U.S. offshore accidents, and there are no reliable injury and fatality rate statistics for offshore operations beyond those compiled by the International Association of Drilling Contractors (IADC) for individual workplace accidents in offshore drilling. The lack of data makes it difficult to evaluate the level of safety achieved by oil and gas operators, safety-related equipment, and Federal regulation. It also makes it difficult to assess the effects on safety when changes are introduced. The data bases that do exist do not separate incidents that occur in frontier regions. To date, there have been no major (catastrophic) accidents in U.S. frontier areas. However, such accidents have occurred to U.S. facilities in other areas.

Several different agencies and organizations keep offshore accident records, using a variety of reporting systems. The Coast Guard requires accidents to be reported if they result in an injury causing absence from work for more than 72 hours. The Bureau of Labor Statistics (BLS) collects data on those accidents which cause the employee to be unavailable for work at the beginning of his next workday. The IADC collects data on accidents which cause 12 hours of work to be lost.

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[12] R. Goldsmith, "Cold and Work in the Cold," *Encyclopaedia of Occupational Safety and Health* (Geneva: International Labor Organization, 1983).

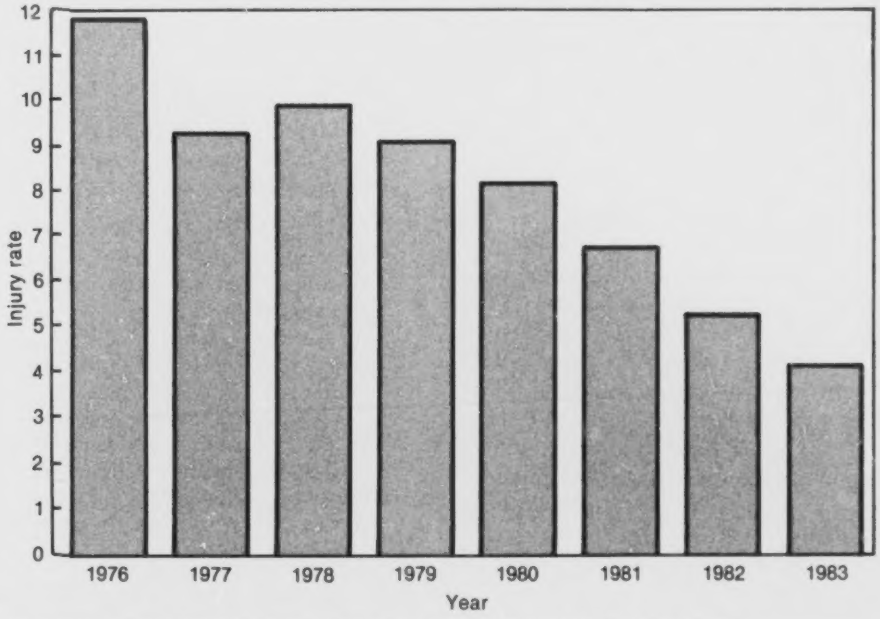
The BLS and IADC standards are roughly comparable, but their statistics often differ due to different data bases. For example, IADC usually reports drilling-related injuries, while BLS covers all aspects. IADC statistics are derived from companies employing about 90 percent of the offshore drilling workers, while BLS relies on statistical sampling. In addition, the IADC does not include accident statistics from catastrophic incidents or accidents involving personnel not employed by drilling contractors, such as oil company representatives and employees of firms providing drilling muds, well cement, or specialty tools. Neither the IADC nor the Coast Guard ordinarily include statistics on accidents and fatalities for helicopter personnel transfer and resupply operations, unless the helicopters and supply vessels collide with offshore facilities.

Injury Rates

Available data indicate that offshore injury rates have declined in recent years (see figure 4-2). IADC figures show the accident rate for offshore drilling has been declining since 1976 equaling a reduction of over 60 percent. However, the IADC reported an increase in the incidence of injuries for the first 9 months of 1984 as compared with 1983. Overall, offshore drilling injury rates are comparable to those in the mining sector and are less than onshore drilling injury rates (see table 4-5).

Using a 72-hour reporting standard and ending with 1981, Coast Guard data show a similar trend for the offshore industry since 1978. According to the Coast Guard, over 80 percent of OCS injuries are caused by human factors, rather than equipment failure. A major cause of accidents is inexperience: about 75 percent of the injuries occur to workers with less than 1 year on the job, and about

Figure 4-2.—Offshore Drilling Injury Rate



Injury rate equals the incidence of lost time accidents per 200,000 man-hours.

SOURCE: International Association of Drilling Contractors.

Table 4-5.—Comparable Industry Injury Rates (1983)

Industry	Injury rate per 200,000 manhours
Total private sector	3.4
Construction	6.2
Mining (other than oil and gas extraction)	4.4
Anthracite mining	6.1
Total oil and gas extraction:	4.6
Onshore oil and gas drilling	10.36*
Offshore oil and gas drilling	4.2*

*Statistics from IADC.

SOURCE: Bureau of Labor Statistics.

30 percent to workers with less than 6 months experience. However, some workers contend that some accidents listed as being caused by human error are the result of unsafe management practice rather than worker carelessness. In boom periods, when operations expand, there is an influx of new workers, and accident rates increase. In slack periods, only more experienced workers are retained.

Fatality Rates

There are fewer reliable statistics on offshore fatality rates. Unlike offshore injuries, the data available show no clear pattern of decline in fatalities. Coast Guard data show the fatality rate (deaths per 210 million man-hours) for offshore drilling fluctuating between 1976 and 1981, with a high of 226 and a low of 80. Fatality rates for the offshore oil and gas industry as a whole fluctuated between a high of 118 and a low of 54 in this time period. The reliability of these statistics is unclear, as the Coast Guard lacks data on man-hours worked.[13]

The Coast Guard is seeking to establish an improved injury and population data collection system. One change will be the collection of data in computer form. Perhaps the most important improvement sought is better information on the number of workers and the hours worked offshore. This is necessary to monitor progress towards the Coast Guard and Federal goal of decreasing injuries and fatalities. If a new permanent data collection system cannot be implemented, the Coast Guard hopes to make a comprehensive assessment of injury and population data in 1988. The last statistical assessment of offshore injury and fatality rates made by the Coast Guard was in 1982.

Consistency among data systems would aid in evaluating the effectiveness of safety measures. A report by the Marine Board of the National Research Council recommended several improvements in the present inspection and data system, including the formation of a system that acquires comprehensive event and exposure data; relates events to specific employers, locations, operations, and equipment; calculates frequency and severity rates, and analyzes trends; and permits monitoring of the relative safety performance of owners and employers, locations, and activities.[14]

The Marine Board also concluded that a single lead agency should be established to handle safety data and recommended MMS in this role. MMS was seen by the Marine Board as having a stronger presence offshore than other agencies, and it believed that MMS would better integrate safety data into day-to-day regulation. On the other hand, the Coast Guard is also a strong candidate since it has the bulk of the offshore personnel safety-related responsibilities.

Safety Regulation

Offshore Regulatory Structure

Under the OCS Lands Act and its regulations, private industry is responsible for ensuring the safety of offshore operations:

> Each holder of a lease or permit under the Act shall ensure that all places of employment within the lease area or within the area covered by the permit on the OCS are maintained in compliance with workplace safety and health regulations of this part, and, in addition, free from recognized hazards . . . . Persons responsible for actual operations, including owners, operators, contractors, and subcontractors, shall ensure that those operations subject to their control are conducted in compliance with workplace safety and health regulations of this part and, in addition, free from recognized hazards.[15]

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[13] Testimony of Thomas Tutwiler, Hearing before the Subcommittee on Panama Canal/Outer Continental Shelf of the Committee on the Merchant Marine and Fisheries, House of Representatives (June 16, 1983).

[14] Marine Board, *Safety Information and Management on the Outer Continental Shelf* (Washington, DC: National Academy Press, 19[illegible]).

[15] 33 CFR Sections 142.1(a) (b).

Private industry responsibility for safety is governed by a complex regulatory structure. Depending on where they are located, offshore facilities are affected by several sets of mandatory and voluntary authorities and standards. These include international agreements and conventions, flag nation standards, coastal nation standards, and nongovernmental organizations.

The International Maritime Organization (IMO), whose membership includes most of the world's maritime nations, sets standards on marine safety, pollution, and navigation. IMO member states have adopted many of these standards as minimum requirements, supplementing IMO standards as deemed necessary with their own regulations. The International Labor Organization also has recommended safety standards in consultation with IMO. Among other related actions, IMO has published a Code for the Construction and Equipment of mobile drilling units (1979) and a convention on Safety of Life at Sea (SOLAS) (1974), which contain many safety recommendations. Recent SOLAS lifesaving requirements include provision of above-water means of escape from enclosed lifeboats in case of flooded capsizings, lifeboat release mechanisms that permit both on-load and off-load releases, and requirements for training on use of all survival equipment, including life rafts.[16]

The nation under whose flag a given mobile drilling unit is registered has its own set of regulatory authorities governing design, construction, and operation of rigs and their equipment. The nation off whose coasts a rig is operating may have jurisdiction over aspects of operation. In addition, state or provincial governments may have additional standards.

Nongovernmental organizations such as the American Bureau of Shipping (ABS) conduct design and construction review and surveys for ships, rigs, and other marine equipment. Most insurance underwriters require classification by societies such as ABS before they will insure a ship or rig. The Coast Guard accepts certain ABS inspections in lieu of direct Coast Guard inspection. Other U.S. private organizations with notable roles include the IADC, which collects accident statistics and advises members on safety matters; the American Petroleum Institute, which publishes standards and recommended practices for facility and component design, construction, and operation, as well as personnel training; the Underwriters' Laboratories, which performs classification and testing for such things as fire protection systems; and the American Society of Mechanical Engineers, which publishes industry codes for piping and pressure vessels.

Federal Safety Responsibilities

The OCS Lands Act gives primary offshore safety responsibilities to the Coast Guard and MMS. The Coast Guard is the lead agency for personnel protection, and enforces most regulations controlling workplace safety. MMS enforces regulations bearing on safety as part of its responsibility for the regulation of drilling and production. Both the Coast Guard and MMS have responsibilities for reviewing the design and construction of facilities. MMS also evaluates installation of fixed facilities to ensure that they are in compliance with plans and that no significant damage has occurred during installation.

Both agencies have regulations covering training, drills, and emergency procedures on offshore facilities. Each agency has provisions for conducting scheduled and unannounced inspections to ensure compliance. The Coast Guard is normally the lead investigating agency for cases of collisions, deaths and injuries, damage to floating facilities, and failures of or damage to propulsion, auxiliary, emergency, and other safety-related systems. MMS is the lead agency for cases of fires and explosions, pollution, and failure of or damage to fixed facilities. For incidents where they do not have lead agency responsibility, each agency participates in any investigation that bears on its jurisdiction.

Other agencies with offshore safety roles include the Occupational Safety and Health Administration (OSHA) and National Institute of Occupational Safety and Health (NIOSH). Memoranda of Agreement have been signed between agencies delineating jurisdictions. The Memorandum of Understanding between the Minerals Management Service and the Coast Guard gives authority for regulating specific operations dealing with drilling to MMS, and other aspects of OCS operations to the Coast Guard.

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[16] Robert L. Markle, "SOLAS Chapter III," *Proceedings of the Marine Safety Council* (January 1984).

COAST GUARD

Coast Guard regulations deal with hazardous working conditions offshore and apply to the performance of safety-related equipment and drills for personnel for the evacuation of facilities. The Coast Guard reviews and approves design, construction, alteration and repair for vessels, rigs, and floating facilities. The Coast Guard also regulates the safety of commercial diving operations.

The Coast Guard is in the process of modifying safety standards for mobile offshore drilling units, fixed structures, and mobile well servicing units. For mobile offshore drilling units, revisions are being considered regarding ballast control, fire protection, and lifeboat and life raft launching under adverse conditions. One proposal would require that a mandatory safety briefing be given to each arrival on board. Other regulatory changes under consideration would apply to fixed as well as mobile facilities.

Other possible changes include: 1) expanding regulations to more specifically cover support units, such as specialized vessels used for standby, supply, and well servicing; 2) expanding workplace safety rules, including personal protective equipment, and guarding of openings; 3) clarifying division of responsibility with OSHA; 4) updating evacuation and firefighting standards; 5) clarifying best and safest technologies (BAST) regulations; and 6) clarifying training requirements.

The Coast Guard also conducts research to improve prevention of offshore work-related injury and illness. Investigations are being conducted on such things as improving the seakeeping characteristics of mobile offshore drilling units. Current research contracts include investigation of ballast systems, tension leg platform design and serviceability, and methods for evacuation of Arctic drilling units.

MINERALS MANAGEMENT SERVICE

MMS, the lead offshore Federal agency, has the power to halt operations or even cancel a lease if it determines that such operations constitute a sufficient hazard. MMS issues OCS Orders for each region that cover such things as well control, production safety systems, pollution prevention and control, and structural safety. Lessees have to show compliance with the orders to obtain permits to drill and produce.

MMS conducts technical reviews and approves design, fabrication, and installation of all fixed OCS facilities. For floating facilities, MMS has approval of the design and fabrication by the Coast Guard. MMS also conducts inspections of facilities to check for compliance with regulations and is the lead agency for the investigation of accidents involving fires, blowouts, and explosions. MMS regulation is done primarily through working with the operator/lessee rather than with contractors or subcontractors.

During inspections, MMS technicians monitor testing of drilling safety equipment, check to see that required equipment is in place, and review records to verify that periodic tests have been performed. Violations can be punished with a warning or order to shut down the operation.

SHARED COAST GUARD/MMS RESPONSIBILITIES

Both the Coast Guard and MMS review design, construction, and installation of offshore facilities. Which agency will be responsible for a given facility depends whether it is fixed on the seafloor or floating. Some facilities may require both Coast Guard and MMS approval, due to their change in character from being a floating facility while in transit to the site to being fixed when on site. The tension leg platform is even more complex. The surface portion and the legs are approved by the Coast Guard while the ocean floor foundation is the responsibility of MMS.

MMS design verification and fabrication inspection are largely conducted by approved third-party verifiers who, while paid for by the construction or operating company, verify to the responsible agency that the facility meets regulatory requirements. An inspection of fixed structures during or immediately after construction or installation is a part of the third-party verification system. Post-installation underwater inspections are not required in subsequent years, but may be needed, particularly in frontier areas.

Post-installation inspection requirements of the legs or the underwater portion of the floating structure of the tension leg platform have not been determined. However, other floating structures certified by the Coast Guard such as mobile drilling units and ships generally undergo a regular docking for inspection. MMS announced its intention in 1980 to develop requirements for periodic structural inspection of fixed offshore facilities.

As new concepts evolve, certification responsibilities may change and certification procedures may be blurred. For example, ocean sub-sea completion systems and future ocean floor production facilities may require different arrangements. The government's regulatory role in the inspection of underwater portions of the structure during the life of the structure is now limited. The government does require structural integrity data from industry after a platform has been installed and is subjected to a major event, such as a storm or collision. As structures become more complex and are located in deepwater or Arctic areas, inspection techniques must also become more sophisticated. Government-sponsored research may be necessary to enhance Federal inspection capabilities for the future.

OTHER FEDERAL AGENCIES

The Memorandum of Understanding between OSHA and the Coast Guard states that the Occupational Safety and Health Act (which is enforced by OSHA) applies to offshore working conditions, but "does not apply to working conditions with respect to which the Coast Guard or other Federal agencies exercise statutory authority to prescribe or enforce standards affecting occupational safety and health." OSHA enforces standards in State waters out to the 3-mile limit (out to 9 miles for Texas and Florida), except in California and Alaska, which administer federally approved safety and health programs. OSHA does not conduct separate offshore inspections. If Coast Guard inspectors detect violations of OSHA standards in the course of inspections, they notify OSHA. The two agencies have agreed to coordinate activities and exchange data in areas where they may overlap. OSHA turns over to the Coast Guard all worker safety and health complaints, while Coast Guard makes available to OSHA the results of Coast Guard accident investigations. OSHA is proceeding with rulemaking to improve workplace standards for onshore oil drilling and servicing, which could be useful to offshore operations.

Other Federal agencies with lesser roles include NIOSH, U.S. Department of Health and Human Services; and BLS of the U.S. Department of Labor. NIOSH does research related to preventing work-related injury and illness. They have sponsored research on diving hazards and on identifying injury causal factors on drill rigs. They have recently released recommendations for protecting workers on land-based drill rigs which may partly apply to offshore drilling operations. The BLS is responsible for collecting and reporting statistics for work-related injury and illness.

Arctic Search and Rescue

Offshore development in the Arctic presents special safety problems. Ice, extreme cold, occasional white-outs and fog, and possibly, long distances from human settlements, make evacuation difficult. It is uncertain how evacuation will be conducted from rigs surrounded by ice. Conventional lifeboats and land capsules cannot be used. For the near future at least, helicopters, suitable fixed-wing aircraft, and/or icebreaking ships will have to be maintained by private or Federal sources. Because of lack of Federal resources, it is likely that offshore developers will have primary responsibility for their own rescue efforts.

The Coast Guard is the lead Federal search and rescue agency in maritime regions. It coordinates its efforts with those of other Federal agencies, especially the Department of Defense, and with State and local governments and the private sector.[17] In addition, the Coast Guard reimburses fuel expenses for the Coast Guard Auxiliary, a volunteer organization that performs about one-fifth of Coast Guard search and rescue missions. The Air Force is lead agency for search and rescue in land areas and is frequently called on for maritime search and rescue. The Air Force also operates the Mission Control Center at Scott Air Force Base, Illinois, through which Search and Rescue Satellite Aided Tracking (SARSAT) rescues are coordinated. Many rescues have been made through the Civil Air Patrol and Coast Guard responding to SARSAT information.

SARSAT is a search and rescue package mounted on one NOAA polar orbiting meteorological satellite. Three Soviet cosmos satellites in the COSPAS system also have search and rescue sensors. Eventually, the system will probably consist of two U.S. and two Soviet satellites. As of December 1984, over 300 people have been rescued as a result of COSPAS-SARSAT in the brief period of time in which these satellites have been in operation. About half of these people were U.S. citizens.

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[17] U.S. Coast Guard, "National Search and Rescue Plan" (1981).

SARSAT detects emergency signals from small inexpensive transmitters activated on ships, aircraft, and other vessels in distress. SARSAT offers many advantages, especially in remote areas such as the Arctic, where ship and aircraft passages are infrequent and they may not be found when in distress. Locating vessels is much faster if they are equipped with SARSAT transmitters. However, the Administration has proposed placing SARSAT aboard LANDSAT or another satellite and its future is uncertain.

Some deficiencies have been identified in Coast Guard capabilities to carry out search and rescue missions. Problems include age of vessels, lack of adequate maintenance, lack of training of personnel, excessive overtime required of personnel, and problems in retaining experienced personnel. Personnel policies that have increased the concentration of Coast Guard officers in desk jobs and decreased rotation have been criticized as lessening the amount of experience officers would otherwise gain in search and rescue.[18]

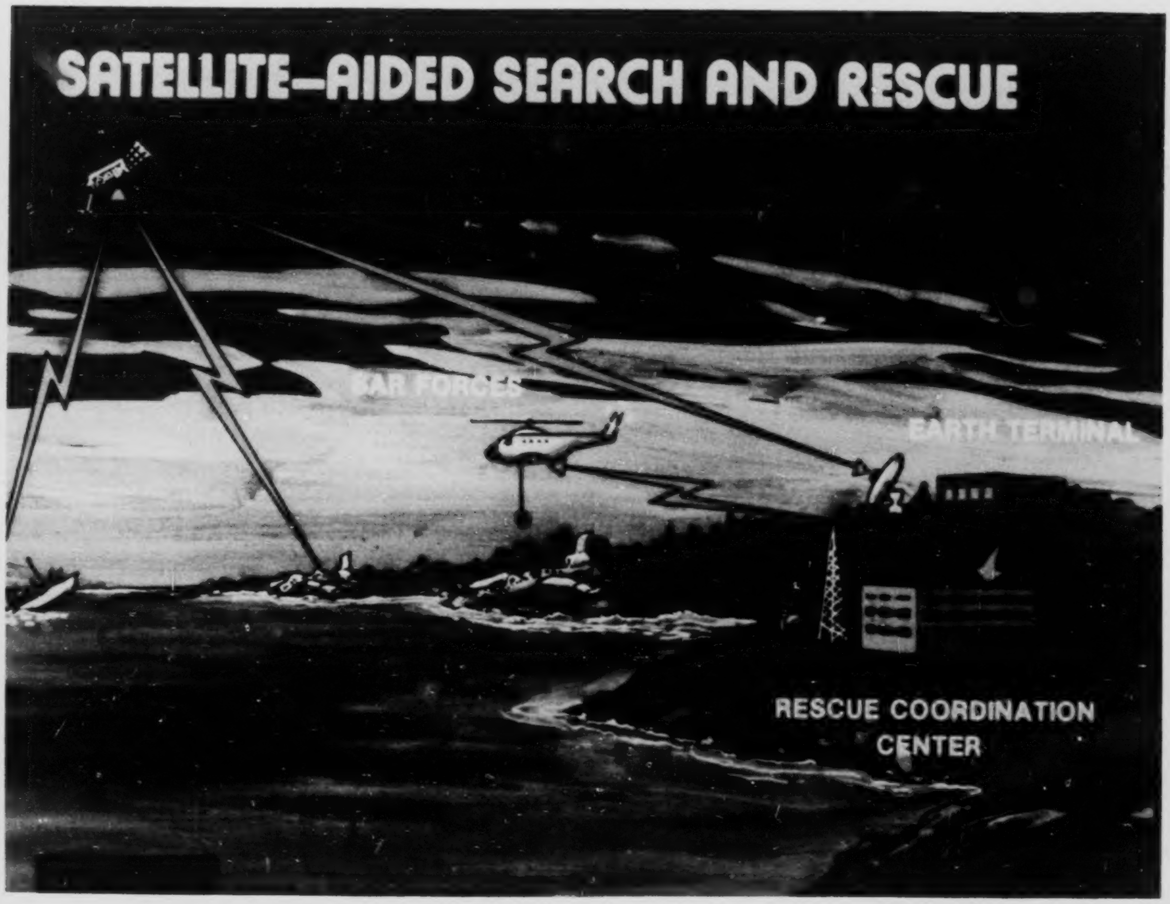

Photo credit: NOAA

The Soviet Union and the United States cooperate in satellite search and rescue in the Arctic

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[18] Congressional Research Service, "The U.S. Coast Guard" (Mar. 1, 1982).

There has been little demand for Arctic search and rescue, due to the lack of commercial and recreational activities in the region. It is reasonable to assume that given expansion of Arctic offshore activities, incidents requiring some search and rescue operations will increase.

However, Coast Guard search and rescue capabilities are constrained in the Arctic. All Coast Guard units in the 17th District are located far from Arctic offshore areas—the closest unit is a small LORAN station at Port Clarence, about 400 miles from Barrow—and all of the major units are on the other side of the State. The ice-strengthened vessels stationed in Alaska are designed for light ice conditions. No unit has icebreakers capable of transiting ice 3 feet and greater in depth, as would be essential for search and rescue during most of the year in northern Alaskan waters. The nearest such vessel, the Polar Sea, is in the Arctic approximately 5 months out of the year (February through April and September through November). At other times, it is based in Seattle, Washington, several days voyage from offshore Arctic sites.[19]

Due to the distance of Coast Guard stations from Arctic operations, lack of permanently stationed icebreakers, and lack of icebreakers capable of winter-round operations, current Coast Guard Arctic search and rescue efforts depend largely on air operations out of Kodiak, Alaska. Air operations are limited by darkness and weather conditions.

The Coast Guard currently has no plans to establish a more permanent Arctic presence, and many search and rescue tasks in the Arctic will be performed by industry itself rather than by the Coast Guard. Industry vessels and helicopters positioned in northern Alaska will have swifter response times than Coast Guard units. Several industry helicopters are already available at Prudhoe Bay. The Coast Guard will coordinate search and rescue efforts of various entities when appropriate.

Improving Offshore Safety

There are economic incentives for the industry to prevent accidents, which can mean time lost from operations and money spent defending against lawsuits. Insurance rates reflect safety records and insurance costs can become exorbitant as a result of bad safety records. Industry believes that more government regulations are not needed to improve safety and that the industry is already overregulated. The Marine Board of the National Research Council concluded that:

> . . . current technology and engineering systems now in use on the OCS appear to provide adequate workplace safety . . . there is no evidence that additional regulations regarding workplace safety are needed for frontier areas nor that major developments in workplace safety technology are indicated.[20]

However, the Marine Board and others have pointed out possible improvements that could be made in technologies, training, management techniques, and regulation to improve offshore safety. What constitutes a reasonable level of safety, and what costs are reasonable to reach that level, is a subjective decision. Improvements to workplace safety are possible in at least three areas: 1) evacuation, 2) management, and 3) regulation.

Evacuation

Offshore rigs may carry several types of craft for evacuation of personnel in emergency situations. These include life boats, survival capsules (a type of covered lifeboat designed for heavy seas), and inflatable life rafts. With the exception of life rafts, these craft are generally boarded on the rig and then lowered into the water. While there have been many safe evacuations, it is often difficult to launch these craft from offshore rigs. Factors such as high winds, heavy seas, height above water (craft may have to be lowered 50 or more feet) and awkward positioning (rigs may be listing 10 or more degrees at the time of evacuation) make the launch hazardous. In some cases, such as the Alexander L. Kielland and Ocean Ranger, evacuation craft have been battered against structures, killing and injuring personnel. Though all launching systems are vulnerable to weather conditions, new systems utilizing free-falling boats reduce launching dangers by removing personnel more swiftly and placing them further away from rigs.[21]

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[19] Marine Board, "U.S. Capability to Support Ocean Engineering in the Arctic" (January 1984).

[20] Marine Board, *Safety and Offshore Oil,* p.15.

[21] Det Norske Veritas, "Evacuation of Personnel by Sea" (August 1983), pp. 11-13.

Facilities surrounded by ice have special evacuation problems. Different methods of evacuation from those used on water are being investigated, including air-cushioned vehicles and vehicles using Archimedean screw propulsion. While these systems are suitable for some ice conditions, they have problems, including difficulty in negotiating steep pressure ridges. The Coast Guard is now testing a Norwegian free fall system, and should soon issue an approval which would allow rig owners to install the system. Another system utilizing ramps to direct survival craft away from rigs is still in the conceptual stage.

Personnel can also be evacuated from offshore structures, lifeboats and other craft, and from the water itself by helicopter, standby vessel, or a ship dispatched from shore. Legislation has been introduced to require that standby vessels be stationed nearby offshore facilities. Vessels not stationed in the immediate vicinity could not arrive quickly to assist at isolated facilities, and even helicopter rescue may take a long time, depending on the location of facilities in distress and of the helicopters themselves. (If standby ships are not stationed close by, they suffer the same disadvantage. The standby ship for the Ocean Ranger was 8 miles away at the time it was radioed for assistance.) Helicopters may not be able to operate in severe weather conditions and are less suitable for evacuating divers suffering decompression injuries. The psychological reassurance brought to personnel by knowledge that a boat is nearby also may be considered.

Standby vessels are required in Norway, Great Britain, and Canada. In the United States, standby boats are not required by regulation but are stationed voluntarily by some employers. Standby vessels may not always be the most appropriate means of evacuation. For example, helicopters can take injured people to shore more quickly than can a ship and are not impeded by sea states. In some ice conditions, aircraft, icebreakers, or ice-strengthened rescue ships would be necessary. A Norwegian governmental commission investigating the Alexander L. Kielland incident concluded that the Norweigan requirement that standby vessels be stationed be abolished in favor of regulatory flexibility.[22]

Separate investigations of the Ocean Ranger sinking by the National Transportation Safety Board and the U.S. Coast Guard Marine Board of Investigation recommended that the Coast Guard require owners or operators to provide standby vessels. The Coast Guard Commandant, however, did not concur. Coast Guard regulatory revisions will rule on standby vessels.[23]

The safety of evacuation methods might be best advanced through performance requirements. Without specifying a system, employers could be required to provide adequate means to evacuate personnel within a certain time. Performance standards have the advantage of increasing the flexibility of employers in meeting requirements. The Coast Guard plans to increase use of performance standards in several areas, using industry standards as a guideline.

Even if rescue ships or helicopters arrive swiftly, they may not be able to recover personnel without specialized equipment. In the case of the Ocean Ranger, standby ships were unable to rescue anyone despite courageous attempts, mostly due to the lack of nets, baskets, cranes, or other systems which could be used to recover persons too weak to assist themselves. Other problems discovered in the course of investigations of the Ocean Ranger incident included design limitations of the standby ships (e.g., high freeboard), lack of training and protective clothing for their personnel, and lack of facilities for treating hypothermia.

Injuries also occur in the course of transferring people between offshore structures and standby boats. Usually, personnel are transferred using baskets or nets suspended from cranes. Extendable, flexible bridge concepts are being explored by some sources.

Management

Responsibility for safety is not always clearly delineated on offshore rigs. A common practice has been for Toolpushers (drilling supervisors) to be formally in command while rigs are anchored, while Masters (maritime captains) are in command while the rig is being moved. In addition, a representative of the company contracting out the unit may have considerable informal authority. This arrangement has at times resulted in confused lines of responsibility, especially during emergencies. Poor coordination between the drilling unit and shore-based personnel and lack of a well-defined chain of command can slow response time, as was demonstrated in the Ocean Ranger incident. The Coast Guard has undertaken a review of licensing regulations in order to clarify rules for assignment of responsibility.

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[22] Olav Kaarstad and Egil Wulff, *Safety Offshore* (Oslo, Norwarry: Universitetsforlaget, 1984), p. 5.

[23] U.S. Coast Guard, *Mobile Offshore Drilling Unit (MODU) Ocean Ranger* (May 20, 1983).

In addition, safety problems and solutions often lie in the attitudes and actions of personnel, rather than equipment. Some offshore companies and drilling contractors give safety a high priority using the safety records of prospective contractors as an element in the bid selection process. Many companies hold safety meetings where workers can voice safety concerns.

Training is the foundation for safety. MMS requires that training be given to specialized personnel. Many offshore companies operate training schools or pay for employees to attend such schools. However, investigations of catastrophic offshore incidents have found that training of personnel, including those responsible for operating systems crucial to the safety of others, has been inadequate on some rigs. For example, no one on board the Ocean Ranger had more than a rudimentary understanding of the ballast control system, and there were no trained lifeboat crews.

Among other applicable regulations, the Coast Guard requires that emergency drills be held at least once each month on manned offshore facilities. For mobile drilling units, a boat drill is required at least once each week in which all personnel report to their stations and demonstrate their ability to perform their assigned duties, and weather permitting, at least one lifeboat is partially lowered and its engine started and operated. Each lifeboat is to be lowered to water, launched, and operated at least once every 3 months. There are, however, no requirements that Federal inspectors witness and evaluate the adequacy of evacuation drills on OCS facilities.

According to some observers, drills are not held according to this schedule or are *pro forma* exercises on some rigs, held only to meet minimum regulatory requirements. Similarly, personnel have reported that they have not been informed of their emergency assignments even though posting of such information is required. Periods of large turnover of personnel on rigs increase the difficulty of establishing a high degree of proficiency (e.g., through teamwork) in safety-related tasks. The Marine Board has recommended that Federal regulations include mechanisms that promote more active company attention to safety, such as pubic visibility and accountability, safety performance standards, and personnel standards.

Regulation

Despite the great number and variety of regulatory requirements bearing on offshore safety, there are no specific requirements that employers submit safety plans that aim at an integrated assessment of the adequacy of safety measures, such as drills, evacuation plans, and lines of responsibility. There are existing requirements that bear on planning, but there is no separate rig-by-rig review that looks at all of the components of technology and management practices that are involved in offshore safety.

Regulations mandate scheduled inspections of all facilities at least once a year, supplemented by an unspecified number of periodic, unannounced inspections. These are performed by the Coast Guard and MMS. A drilling technician inspects rigs on an average of once a month after drilling begins. If a violation is found, sanctions range from a warning, with 1 week given to correct the deficiency, to shutdown of the piece of equipment, the well, or the entire operation. Also, an investigation is conducted following any accident, and notices are sent to all lessees and operators describing incidents, apparent causes, and actions taken by operators to prevent a recurrence. Civil and criminal penalties are provided for infractions of requirements.

However, the Ocean Ranger disaster pointed out important deficiencies in Coast Guard inspection procedures. After the initial inspection in December 1979, no subsequent formal inspections of the Ocean Ranger were carried out, aside from one brief visit from an official. Although its certification had expired in December 1981, no reinspection was made up to the time of the February 1982 sinking. Although the Coast Guard directed that the lifeboats and life rafts on the Ocean Ranger be replaced within 2 years, no replacements were made and no effort was made by the Coast Guard to ascertain whether its directive had been carried out. In addition, the rig was not manned according to requirements of its inspection and cargo ship safety equipment certificates.

In general, the Coast Guard relied on the classification given to the Ocean Ranger by the American Bureau of Shipping (ABS) as proof of design adequacy, and the Coast Guard did not independently assess such things as the capability of the ballast pumping system. ABS ratings focus on certification of structure, machinery, and equipment, and do not cover personnel competence, training, or safety management practices.[24]

The Coast Guard has had difficulty in carrying out the required number of inspections on fixed platforms due to funding limitations.[25] It is unclear how the Coast Guard will handle inspections should activities be significantly expanded in Arctic regions. Currently, Coast Guard inspection resources are concentrated in the Gulf of Mexico, and aside from several small LORAN stations, all Coast Guard installations in Alaska are located in southern portions of the State, many hundreds of miles away from frontier areas.

Inspection alternatives considered by the Coast Guard include relinquishing some scheduled inspections to MMS, the lessee, or to a third-party. However, the Coast Guard would continue unannounced inspections on a small percentage of facilities, and worker complaints could trigger other inspections. The main disadvantage of self-certification is the possibility that inspections would be less strict, thereby lowering safety. Third-party inspection analogous to current third-party verification of design and construction would be preferable in this regard, if such firms were held to strict standards. An issue to be resolved is who would bear the cost of third-party inspections. Industry currently pays for third-party verification.

Whether safety levels can indeed be maintained or increased within the Coast Guard's budgetary constraints is uncertain. The Coast Guard believes that savings resulting from delegating inspections will enable it to concentrate resources on the rigs with poor records. Improved data collection is essential to this goal, however.

OSHA does not conduct its own offshore inspections. OSHA's position is that if the Coast Guard exercised authority over workplace safety and health, OSHA authority is superceded. However, the Coast Guard does not have detailed workplace safety rules, and it is unclear which, if any, OSHA rules apply. The Coast Guard has a regulatory project to develop more detailed Coast Guard workplace safety standards. Review is also needed of respective OSHA and Coast Guard responsibilities.

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[24] Royal Commission on the Ocean Ranger Marine Disaster, *Report One: The Loss of the Semisubmersible Drill Rig Ocean Ranger and Its Crew* (Canada: Canadian Ministry of Supply and Services, 1984).

[25] Thomas Tutwiler, in *Proceedings of Safety of Life Offshore Symposium* (International Association of Drilling Contractors and Scripps Institute of Oceanography, June 1983), p. 54.

Chapter 5

Economic Factors

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Chapter 5

Economic Factors

OVERVIEW

Exploration and development of oil and gas resources in the Arctic and deepwater frontiers depend largely on potential profitability. Economic incentives are needed for industry to develop the technology for resource development in the frontiers. Factors which influence project profitability include costs, timeframes, prices, markets, and government lease and tax payments. In general, higher costs and longer lead-times to production tend to lower profit margins in offshore frontier areas. As a result, the sensitivity of project economics to changes in various factors is higher in frontier areas than in mature producing regions such as nearshore Gulf of Mexico.

OTA has analyzed the economic attractiveness of oil and gas development in offshore frontier regions. Using a computer simulation model, cash flow profiles were developed for different types of offshore fields based on the technical scenarios presented in chapter 3. Ten hypothetical fields are discussed, consisting of representative large and small fields in nearshore Gulf of Mexico, California deepwater, and three Alaskan basins. The estimates of costs, timeframes, and other variables used in the model are only approximations of those which may be encountered with actual projects in these offshore areas. The results of the simulations do not represent the actual economics of prospects. They are used principally to illustrate how changes in economic factors can affect the profitability of oil and gas development in different offshore regions.

Remoteness, difficult operating conditions, and high engineering costs are characteristic of frontier areas. Extremely large oil and gas discoveries are needed to offset the high costs and long timeframes of exploration and development. Small fields may not yield adequate profits to justify development. The OTA analysis shows that while a 40- to 50-million barrel field may be profitable in the Gulf of Mexico, in the Alaskan offshore it may take a discovery of 1 to 2 billion barrels of recoverable reserves to make a project profitable.

Government lease and tax payments affect the profitability of offshore fields differently in the frontiers than in other leasing areas. The OTA computer simulation indicates that leasing systems based on alternative types of lease payments rather than fixed royalties may increase the profits and reduce some of the risks associated with frontier-area fields. In general, the profitability of oil and gas development in offshore frontier areas will be increased by real oil and gas price increases. In the Alaskan regions, the availability of economic market outlets for oil and gas—the development of export markets for Alaskan oil and the development of processing and transportation systems for Alaskan natural gas—could improve the economic profile of offshore fields.

COSTS OF OFFSHORE EXPLORATION AND DEVELOPMENT

Harsh environments and difficult operating conditions greatly increase the costs of oil and gas exploration and development in Arctic and deepwater frontier regions. Costs are important determinants of the economic feasibility of producing oil and gas in offshore areas. In general, offshore exploration and development costs are influenced by the ocean environment (e.g., waves, ice, currents), water depth, field size and flow, proximity to support and transportation infrastructure, and elapsed time to production start up. Long lead-times to first production also add to the risks and uncertainty of frontier-area oil and gas activities.

The major categories of project costs—exploration costs, development costs, operating costs, and transportation costs—have been estimated for hypothetical small and large fields in five offshore regions (see table 5-1). These estimates are based on costs included in the National Petroleum Council study of *U.S. Arctic Oil and Gas* and other sources, and have been escalated to 1984 dollar equivalents.[1] They are not exact figures, but are intended to be indicative of relative cost ranges in different offshore regions. More precise cost estimates can only be derived if and when a discovery is delineated and a production system is designed for a specific site and set of operating conditions.

Exploration Costs

Exploration costs include the cost of the drilling rig, logistical support, exploration wells, and delineation wells. They do not include the lease bonus payment. In this analysis, it is assumed that the wildcat exploratory success rate is 1 in 10 and that each successful discovery includes the cost of drilling 10 exploratory wells. In addition, it is assumed that five appraisal or delineation wells are drilled into each oilfield before development begins, except in the nearshore Gulf of Mexico where only three are drilled. Additional delineation wells are needed for frontier-area fields to justify the high costs of development.

Ocean environment and water depth account for most of the variation in exploration costs owing to requirements for specially designed drilling equipment in hostile environments and to operating conditions that may cause delays. Total exploration costs are generally independent of field size. The average cost of drilling exploratory and appraisal wells in the more conventional Gulf of Mexico leasing area is estimated at $6 million per well. In comparison, single exploratory wells are estimated to cost an average of $27 million in the California deepwater scenario and $55 million in the Navarin Basin of offshore Alaska. In this analysis, the total costs of an exploration program are estimated at $78 million in nearshore Gulf of Mexico as compared to $825 million in the Navarin Basin.

Development and Operating Costs

Development costs include the cost of the drilling platforms or islands and the development wells. In most regions, platforms and facilities account for 65 to 70 percent of total development costs. These costs vary not only with the harshness of the operating environment and water depth, but also with field size. In this analysis, it is assumed that there are no economies of scale associated with platform construction or development drilling, except in the nearshore Gulf of Mexico scenario. There are economies of scale associated with operating costs. Operating costs are calculated on an average annual basis and include labor, repair and maintenance, fuel, power, water, and other support functions.

Development costs for a 50-million barrel oil field in 400 feet of water in the Gulf of Mexico are estimated at $168 million, including platform costs of $112 million and drilling costs of $56 million. These costs escalate quickly with the depth of water and the severity of ice, wind, and wave conditions. Total development costs for a 300-million barrel field in California deepwater (3,300 feet) are estimated at $900 million. Development costs for a 2-billion barrel field in Alaska's Harrison Bay, which has severe ice conditions, are estimated at $6.3 billion, and in the Navarin Basin, with its greater water depth and harsher wind and wave conditions, at over $11 billion. Operating costs range from $10 to $25 million per year in the more temperate and accessible Gulf of Mexico and California regions to $100 to $250 million per year in the Alaskan offshore areas.

Transportation Costs

Transportation costs depend on many factors, including distance from markets, the availability of transportation infrastructure, and the harshness

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[1] National Petroleum Council, *U.S. Arctic Oil and Gas* (December 1981); Dames and Moore, GMDI and Belmar Engineering, *Deep Water Petroleum Exploration and Development in the California OCS*, Report prepared for the Minerals Management Service (January 1984).

Table 5-1.—Comparative Offshore Exploration and Development Costs (estimates for OTA computer simulation)

Area	Water depth (feet)	Field size (mmb)	Exploration cost ($ million)	Development cost ($ million)	Operating cost ($ mill/yr)	Transportation cost ($/bbl)	Production lead-times (years)
Gulf of Mexico							
Small field	400	15	78	105	7	$0.00	2
Large field	400	50	78	168	12	$0.00	2
Cal. Deepwater							
Small field	3300	150	400	450	16	$2.50	10
Large field	3300	300	400	900	24	$2.00	10
Norton Basin							
Small field	50	250	435	1038	72	$6.50	8
Large field	50	500	435	2076	102	$5.00	9
Harrison Bay							
Small field	50	1000	720	3162	120	$12.50	12
Large field	50	2000	720	6324	168	$10.00	12
Navarin Basin							
Small field	450	1000	825	5460	132	$6.50	11
Large field	450	2000	825	10920	240	$5.00	11

NOTE: Costs refer to total, undiscounted outlays, in 1984 dollars.

SOURCE: Office of Technology Assessment.

of the operating environment. In this analysis, these costs are calculated on a per-barrel basis and include the cost of transporting oil from the production facility to the nearest U.S. market. Transportation costs include pipelines, tankers, and transshipment terminals. The costs of transporting oil to markets varies greatly among regions, but decreases with larger field sizes in all regions due to economies of scale.

Because of the availability of transportation systems and processing facilities in nearshore Gulf of Mexico and the ability to share pipelines, transportation costs are assumed to be absorbed in development costs in the Gulf fields. Transportation costs are estimated at $2 to $2.50 per barrel in the deepwater California area, where it is assumed that subsea pipelines are layed in extremely deep water to the West Coast. In the Norton and Navarin Basins of Alaska, where systems involve icebreaking tankers and transshipment terminals for transport to the lower 48 States, costs are estimated at $5 to $6.50 per barrel. The Harrison Bay project, where oil is transported to shore via pipeline and to southern transshipment terminals through the Trans-Alaskan Pipeline System (TAPS), is assumed to have a transportation cost per barrel of $10 to $12. The transportation costs for the California and Alaskan scenarios could be reduced by shared or common facilities which could serve several fields.

Photo credit: American Petroleum Institute

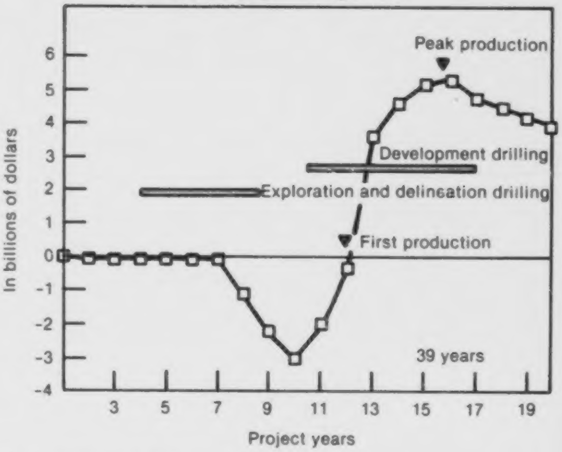
The existence of the Trans-Alaska Pipeline System (TAPS) will affect the economics of oil produced in the Beaufort Sea near Prudhoe Bay

Lead-Times to Production

Far longer time periods are needed for exploration and development in offshore frontier regions than in traditional areas. In the nearshore Gulf of Mexico scenarios, first production is assumed to occur 2 years after the lease sale. In contrast, in the California deepwater and Alaskan scenarios, first production does not begin until a minimum of 8 to 12 years after the lease sale. These schedules may underestimate the actual timeframes of activity in frontier regions, because they assume minimum time for obtaining necessary government approvals. The analysis also assumes that platform design will commence at the time of the discovery and proceed concurrently with the approval process.

For example, it is assumed in the Harrison Bay scenario that 5 to 6 years elapse between the time the lease is acquired and the time when a discovery is made (see figure 5-1). It takes another 5 to 6 years before permits are obtained and production facilities are designed and constructed. It is therefore a minimum of 12 years before the company sees a return on a sizable investment and the discovery contributes to cash flow. Peak production of 500,000 barrels per day occurs in the third year after beginning production. The total life of the field is 27 years from first production.

Figure 5-1.—Corporate Cash Flow
Harrison Bay — Large Field



SOURCE: Office of Technology Assessment.

PROFITABILITY OF OFFSHORE DEVELOPMENT

Potential profits are the primary incentives for investments in offshore oil and gas exploration and development. In general, investments depend on finding sufficient recoverable reserves of marketable oil and/or gas to justify costs. In this analysis, the economic returns to industry and government from offshore oil and gas development are estimated by a computer simulation model (see box). This model calculates the net present value of all expenditures and revenues associated with the 10 hypothetical fields. By discounting these cash flows to the present, the analysis accounts for the time value of money and lost opportunities for alternative investments. The model includes a number of assumptions regarding prevailing economic conditions and the investment and production schedules associated with each oil field. It incorporates all relevant tax and leasing policies.

Economic Rent

The analysis of the net present value of investments has implications for the profitability of alternative investments and for the bidding behavior of firms for offshore leases. The net present value of offshore oil and gas development represents the profits available after a firm has received its normal return to capital, assumed in this analysis to be 10 percent per year. These profits are referred to as "excess profits" or "economic rent." A firm's estimate of its share of the economic rent would be the upper limit to the amount it would be willing to bid as a bonus payment for the right to explore and develop an offshore tract. High competition in a lease sale might lead a firm to bid all of its economic rent as the bonus, leaving it with a normal return on its investment. If the estimate of a firm's economic rent is negative, this indicates that a firm may not make a normal return on the investment.

The Federal Government receives its share of the economic rent from a field in the form of taxes, including corporate income taxes and windfall profits taxes, and lease payments such as production royalties. The tax and leasing system selected by the government is intended to extract economic rent from offshore fields without destroying corporate incentives to undertake the required investments. In designing lease and tax payments, the government must balance the need to obtain fair market value for offshore leases with the need to provide the necessary incentives for development.

The calculation of the net present value of the 10 hypothetical offshore fields shows all of them to

OTA Computer Simulation Model

OTA and outside consultants have developed a computer simulation model to evaluate the economics of offshore oil and gas development projects. The model is based on a standard "discounted cash flow" analysis of the economic potential of investments. For each of ten hypothetical fields (small and large fields in the Gulf of Mexico, deepwater California, and three Alaskan regions), the model calculates the net present value of industry and government revenues based on prescribed parameters. Some of these parameters can be altered to evaluate the effects of changes in various factors on oil field economics.

The descriptive characteristics of the 10 hypothetical oil fields and associated costs are given in *table 5-1*. The simulation of each oil field is deterministic and follows field-specific investment and production schedules. The estimated costs and schedules are intended to be representative of actual conditions that oil companies may encounter in the offshore basins under consideration.

Other model inputs are financial parameters which describe the general economic environment in which exploration and development take place. Fiscal parameters incorporate applicable government tax and leasing regulations. The sensitivity of field economics to changes in prices, leasing systems, or taxes can be assessed by altering these parameters. The financial and fiscal parameters given below are those used in the base case model simulations.

Base Case Financial Parameters:	
Crude oil market price, mid-1984 ($ per barrel)	$29.00
Growth rate of real oil price (annual)	0 percent
General inflation rate	8 percent
Corporate discount rate (real terms)	10 percent
Project financing (debt/equity)	0 percent
Base Case Fiscal Parameters:	
Production royalties (fixed)	12½ percent
Rental fees (per acre)	$3.00
Corporate income tax (marginal rate)	46 percent

Taxable income was reduced by immediate expensing of dry hole costs and 80 percent of intangible drilling costs; depreciation of 20 percent of intangible drilling costs and 95 percent of tangible drilling costs; and the 10 percent investment tax credit.

Companies are assumed to have sufficient income from other sources in the United States to make use of all allowable tax deductions and credits as soon as they become available.

Financial calculations are based on a "full-cycle" treatment of the exploration/development process. In the fixed royalty cases, the cost of nine dry wildcat wells is associated with each field (wildcat success rate of one in ten).

Windfall Profits Tax (1984 rate on new oil)	22.5 percent

The Windfall Profits Tax does not apply to Arctic areas and is scheduled to expire after 1993. It thus should not affect frontier-area fields. In the model, this tax is only levied on the nearshore Gulf of Mexico fields.

be profitable in terms of total available economic rent (see table 5-2). However, the government takes more than its share of the economic rent from two of these fields—the small fields in the Gulf of Mexico and in the high-cost Navarin Basin. In this analysis, Government payments include a royalty rate of 12½ percent and corporate income taxes on the deepwater and Arctic fields. Windfall profits taxes, which should expire by the time frontier-area fields begin production, are levied only on the near shore Gulf of Mexico fields. In addition, the Gulf of Mexico fields are assessed the traditional royalty rate of 16⅔ percent. The fields which show a negative corporate net present value might not be developed under the assumed cost, price, and leasing conditions.

Minimum Economic Field Size

In high-cost offshore regions, very large field sizes are needed to offset exploration and development costs and still yield a normal return on investment. The amount of recoverable reserves needed to yield a normal economic return after subtracting costs and government payments is termed "minimum economic field size." In the offshore frontier areas,

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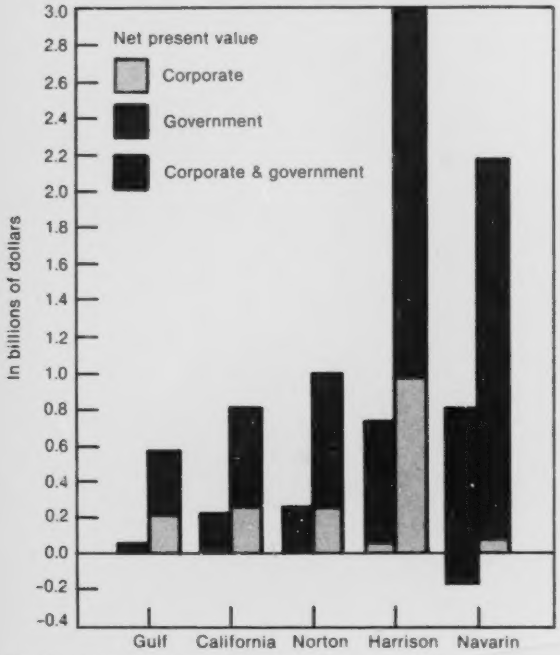
Table 5-2.—Profitability of Offshore Development
(from base runs of OTA computer simulation)*

Area	Water depth (feet)	Field size (mmb)	Net present value ($ million) Total	Corporate	Government	Government share (percent)
Gulf of Mexico						
Small field	400	15	62.9	-0.6	63.5	101
Large field	400	50	563.0	211.9	351.1	62
Cal. Deepwater						
Small field	3300	150	223.2	28.2	195.0	87
Large field	3300	300	807.2	264.1	543.1	67
Norton Basin						
Small field	50	250	261.9	7.6	254.3	97
Large field	50	500	978.0	264.4	713.6	73
Harrison Bay						
Small field	50	1000	735.2	81.8	653.4	89
Large field	50	2000	2989.4	955.8	2033.6	68
Navarin Basin						
Small field	450	1000	780.6	-149.9	930.5	119
Large field	450	2000	2176.5	121.2	2055.3	94

*Government payments include 12½ percent royalties and corporate income taxes on frontier fields; 16⅔ percent royalties corporate income taxes, and windfall profits taxes on nearshore Gulf of Mexico fields.

SOURCE: Office of Technology Assessment.

Figure 5.2.—Profitability of Offshore Development
Small and Large Fields



SOURCE: Office of Technology Assessment.

far greater reserves are needed to yield profitable investments because of the greater costs and longer period of time over which these costs must be carried before repayment begins.

The analysis shows that reserves of approximately 40 to 50 million barrels of oil would support development in 400 feet of water in the Gulf of Mexico. However, a 100- to 150-million barrel field must be discovered to justify development costs in a deepwater environment, as in the California scenario. In the Alaskan offshore scenarios, minimum economic field sizes are as great as 250 to 500 million barrels of oil. In the difficult operating conditions of the Navarin Basin, even the 1-billion barrel field may not be profitable for a company to develop (see figure 5-2).

GOVERNMENT LEASE AND TAX PAYMENTS

The combination of lease payments and taxes levied on offshore fields by the government affects the degree of profit- and risk-sharing between industry and government in oil and gas development. Activities in offshore frontier areas are differentiated by their small profit margins and their higher level of risk and uncertainty. For this reason, government payments affect frontier-area fields differently than those in other leasing areas.

Fixed Royalties

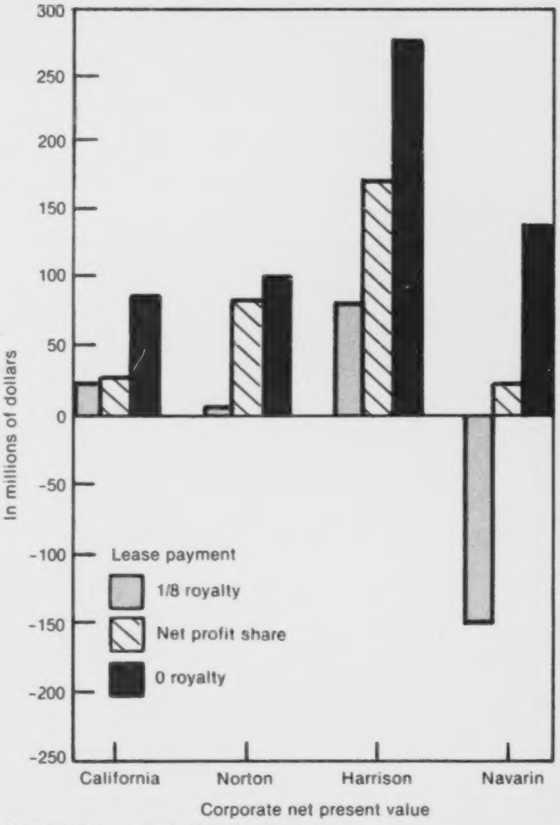
In addition to the initial cash bonus payment, lease payments in the United States traditionally have been fixed royalties based on the value of the resources produced. The royalty rate has been decreased from the standard 16⅔ percent (one-sixth) to 12½ percent (one-eighth) in offshore frontier areas to improve the economics of resource development. Fixed royalties are levied on gross income and are counted as an addition to development costs in analyzing the potential profitability of projects. With fixed royalties, there is no allowance for such factors as field size, production costs, and lead-times to production when taking the government's share of the economic rent. In offshore frontier areas, where costs are higher and lead-times longer, fixed royalties may overtax fields and remove the economic incentive for development.

In general, royalty rates can alter production decisions on small or marginal fields, which in frontier areas may contain substantial resources. In the OTA analysis, the small field in the Navarin Basin is unprofitable to develop under fixed royalties, even though it is assumed to have reserves of 1 billion barrels of oil (see figure 5-3).

Other Lease Payments

Alternative lease payments may be more effective in promoting oil and gas development in offshore frontier areas. Profit-shares and sliding scale royalties are two types of payments believed to promote greater profit- and risk-sharing between industry and government. Eliminating lease payments would provide an even greater incentive to exploration and development in frontier areas. In this case, the government would receive its share of the economic rent through cash bonuses and taxes.

Figure 5-3.—Alternative Lease Payments Effect on Marginal Fields



SOURCE: Office of Technology Assessment.

Although there are several types of profit-sharing systems, the United States has used a "fixed capital recovery" profit-sharing system in tests in offshore leasing. There have been 215 tracts sold with this type of lease payment between 1980 and 1983. Firms share at least 30 percent of their profits with the government, but first recover their initial investment and the cost of carrying that investment from year to year. Cost recovery is allowed according to a set formula or "capital recovery factor."

Because the lease payment is levied on net income, profit-sharing systems allow for the high costs of production in frontier areas and can provide incentives for the development of most field sizes. The capital recovery factor also takes into account the long timeframes of frontier-area projects, so that a company is not taxed too early in the life of the field. When profit-sharing with a 200 percent capital recovery factor is used as the lease payment in the OTA simulation, the small Navarin Basin field becomes profitable to develop (see figure 5-3).

The major disadvantage of profit-sharing systems is that they are more difficult to administer than royalty lease payments. In the fixed capital recovery system, profit share rates and capital recovery factors must be established prior to lease sales and calibrated to the operating conditions of different regions. Other types of profit-sharing systems, such as a symmetric system where the government shares in both profits and losses, could reduce the pre-lease analytic burden. Symmetric profit-sharing also has superior risk-sharing features. However, in most profit-sharing systems, the costs and profits associated with individual fields must be calculated and verified, thus requiring government access to industry cost information. Profit-sharing systems generally require more extensive recordkeeping on the part of both the industry and government.

The advantage of sliding scale royalties is that they vary with production rates, and thus extract a lower payment from smaller and/or less productive fields. However, the OTA analysis showed that sliding scale royalties perform no better than fixed royalties as neither can be set below the legal minimum of 12½ percent. Because of the low profit margins in frontier areas, most fields cannot bear a lease payment above the minimum royalty even at higher rates of production. A zero royalty or a sliding scale royalty which slides down to zero may be appropriate to high-cost frontier regions. A zero royalty makes the deepwater and Arctic fields far more profitable to develop (see figure 5-3).

PRICES AND MARKETS

Market Prices

Current and anticipated market prices are important incentives to exploration and development activities. Crude oil prices can have a major impact on the profitability of offshore frontier fields, particularly small or marginal fields. Fields which are uneconomic under current market conditions may be profitable given an increase in real crude oil prices. Similarly, decreases in real prices can remove the economic incentive to develop offshore resources. Present predictions are for real oil prices to decline in the short term and rise in the long term. Investments made now in oil and gas projects will be based on long-term views of energy markets, real price trends, and technological developments.

It is assumed in the OTA base case model simulations that there is no increase in the real price of oil, and that any associated natural gas is not produced because of low market prices or lack of available markets. According to the OTA analysis, a 1-percent increase in the real price of oil could substantially increase corporate returns (measured as net present value) for the oil field scenarios in offshore frontier areas. The previously unprofitable Navarin Basin field in Alaska becomes economic to develop with the real price increase. Higher oil prices, however, simply change the size of the marginal fields rather than eliminate them.

Alaskan Oil Markets: Export of Alaskan Oil

Restrictions on the export of Alaskan oil can result in increased costs of transporting offshore oil to U.S. consuming markets and reduce the profitability of Alaskan offshore fields. The Prudhoe Bay field, discovered on Alaska's North Slope in 1968, contains 10 billion barrels of oil reserves and is the largest single source of oil in the United States. In the 1970s, concern about dependence on foreign oil imports prompted Congress to enact a series of laws placing restrictions on the export of oil produced on Alaska's North Slope and in offshore areas. The Alaskan oil export restrictions of the

Export Administration Act of 1979 expired in February 1984. Currently, export of Alaskan oil is being restricted by other statutes.

About half of the oil now produced on the North Slope is shipped to California and West Coast markets, and the remainder is transported through the Panama Canal or the Trans-Panama Pipeline to U.S. markets on the Gulf Coast and Atlantic seaboard. Removing the ban on Alaskan oil exports to allow shipment to Asian markets could reduce the transportation costs of the producers, if these foreign markets could be developed. However, this could have negative impacts on the U.S. maritime industry now engaged in the Alaskan oil trade and on overall U.S. energy import requirements.

The cost of transporting Alaskan oil to the Gulf Coast is high because of the long distance and the requirement under the Merchant Marine Act of 1920 (the Jones Act) that this oil be carried in U.S. flag tankers. It is estimated that it costs $4.20 per barrel to ship oil from Alaska to the Gulf Coast in U.S. flag tankers as compared to a cost of $0.90 per barrel for shipment to Japan in U.S. flag tankers and $0.50 per barrel for shipment to Japan in foreign flag tankers[2] (see figure 5-4). A transportation cost savings from exporting Alaskan oil to closer markets could increase the wellhead price received for oil produced from onshore and offshore fields.[3] The higher profits, which would be distributed among the producers and Federal and State governments, may have effects similar to a price increase in improving the development prospects of marginal fields.

The North Slope tanker trade to the Gulf Coast currently engages approximately 40 percent of the ships in the U.S. tanker fleet and 65 percent of the U.S. shipping capacity. The U.S. Maritime Administration estimates that the loss from eliminating this trade would be 68 ships and over 4,000 jobs, and that it might also jeopardize $600 million in outstanding Federal loan guarantees on the tankers.[4] Many North Slope oil producers have investments in tanker capacity and also are ambivalent about exporting oil to markets outside the United States.

Small tankers needed by the Department of Defense in times of emergency could be displaced by removing the export ban. About one-third of the

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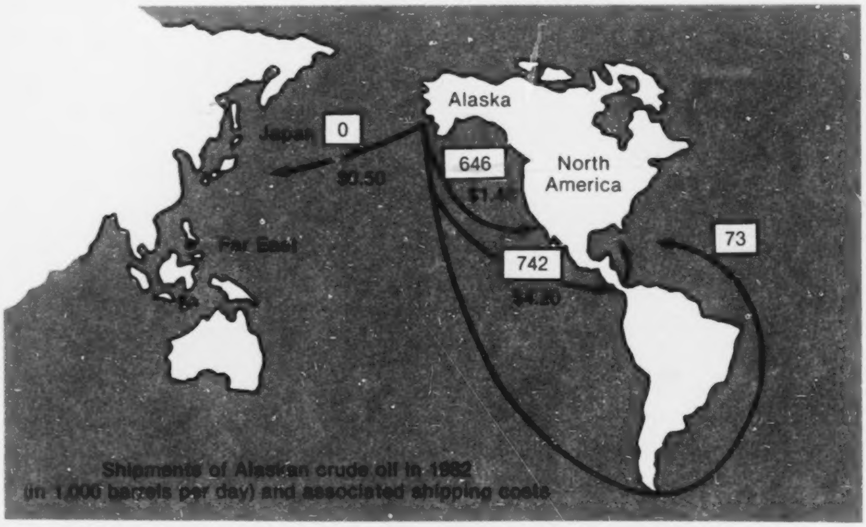
[2] Stephen Eule and S. Fred Singer, "Export of Alaskan Oil and Gas," in *Free Market Energy*, S. Fred Singer (ed.) (New York: Universe Books, 1984), p. 123.

[3] Congressional Research Service, "Exports of Domestic Crude Oil" (Dec. 8, 1983), pp. CRS 4-6.

[4] General Accounting Office, "Pros and Cons of Exporting Alaskan North Slope Oil" (Sept. 26, 1983), p. 10.

Figure 5-4.—Flow of Alaskan Crude Oil


Alaska
Japan
0
$0.50
646
$1.4
North America
Far East
742
$4.20
73
Shipments of Alaskan crude oil in 1982
(in 1,000 barrels per day) and associated shipping costs

SOURCE: Stephen Eule and S. Fred Singer, *Free Market Energy* (New York: Universe Books, 1984).

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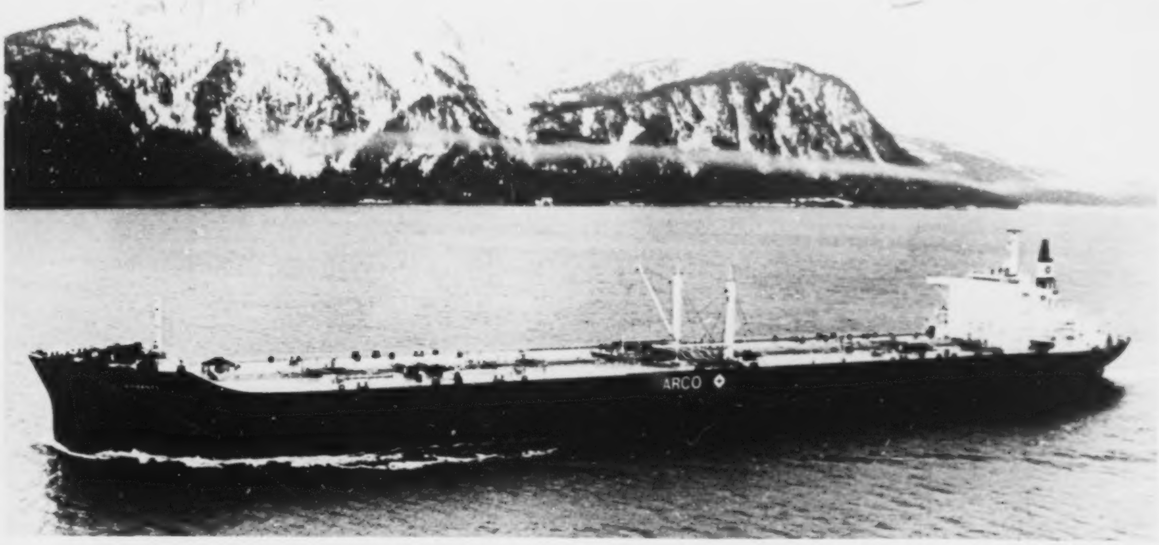

Photo credit: ARCO

Alaskan oil is now transported by tanker to refining centers in the lower 48 States

tankers used in the North Slope oil trade have potential military use because of their small size (less than 80,000 deadweight tons) which permits them to haul products into foreign harbors. It is estimated that removing the Alaskan oil export ban would eliminate about 13 percent of the supply of tankers available to the military for defense needs.[5] In addition, it would be difficult to ship Alaskan oil domestically in the event of a national emergency if this idle transportation capacity were eliminated.

Although exporting Alaskan oil to Japan could substantially improve the U.S. trade deficit with that country, it would somewhat increase the U.S. overall dependence on oil imports. Substitute oil for U.S. refineries could be imported partly from nearby sources such as Mexico and Venezuela, but a share also may be imported from Middle Eastern countries. This would decrease overall U.S. energy security, which the Alaskan oil export ban is designed to increase. In addition, severe economic losses would be suffered by Panama, which would lose revenues from the transit of Alaskan oil through the Panama Canal and the Trans-Panama Pipeline.

In the short-term, Japan is constrained in its need for U.S. oil by world energy surpluses and contractural commitments to other suppliers.[6] However, in the long term, Japan might benefit from access to a secure source of oil and might be more receptive to importing oil from Alaska. In addition, new oil reserves for throughput of the Trans-Alaskan pipeline will be needed as Prudhoe Bay production begins its decline in the late 1980s. Lifting the oil export ban for offshore fields, which probably will not come on stream until the mid-1990s or later, could provide an incentive to exploring and developing costly Arctic areas and new reserves for the pipeline.

Alaskan Natural Gas Markets: Alaskan Natural Gas Transportation System

A system for transporting Alaskan natural gas to U.S. consuming markets could also increase the profitability of Alaskan offshore fields. Planning and financing of the Alaskan Natural Gas Transportation System (ANGTS), the pipeline system intended to transport Alaskan natural gas to the lower 48 States, is currently on hold. Alternative processing and transportation systems have been proposed, but have the same cost and financing problems as the ANGTS.

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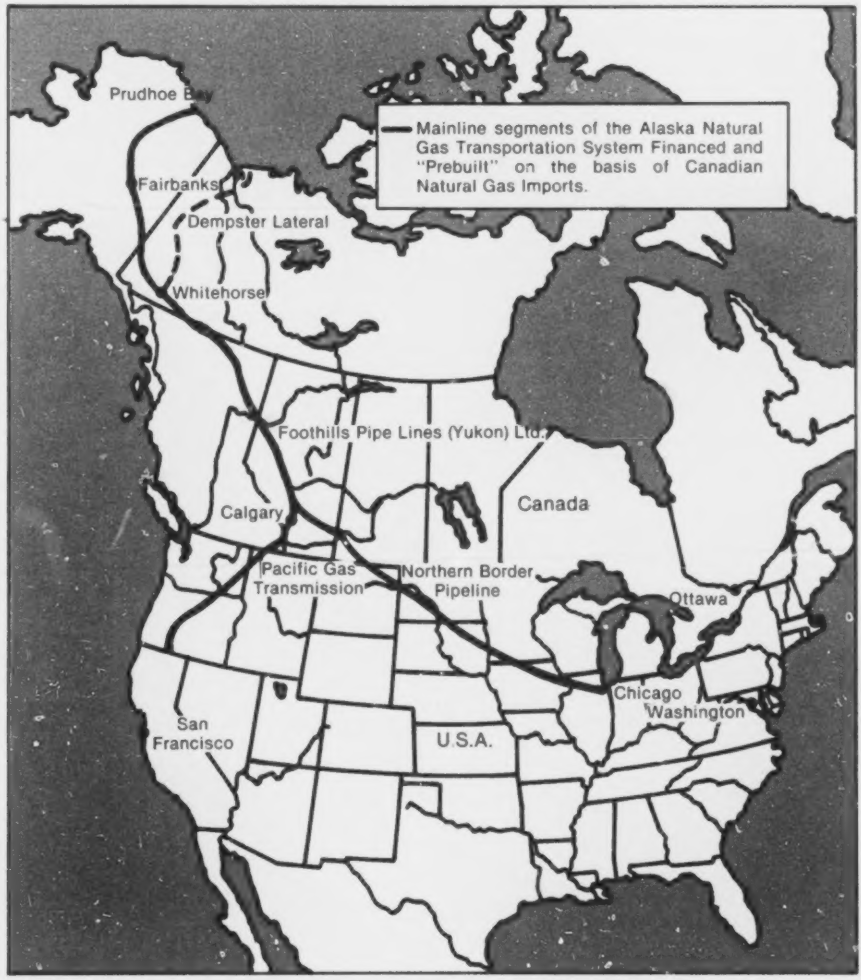
[5] Congressional Research Service, "Exports of Domestic Crude Oil" (Dec. 8, 1983), p. 7.

[6] "Japan Doesn't Want Alaskan Oil Anyway," *Business Week* (Mar. 12, 1984), p. 25.

Construction of the Alaskan segment of the pipeline has been postponed until economic and energy market conditions allow project financing. The ANGTS is designed as a 4,800-mile pipeline network carrying natural gas from Alaska's North Slope to the U.S. West Coast and the Midwest. Plans were made for the construction of the ANGTS during the domestic energy shortages and sharp oil price increases of the mid-1970s. However, by the time ANGTS plans were completed in 1981, there were energy surpluses and depressed prices. The only sections of the pipeline which have been completed are the Eastern and Western legs transporting natural gas from Calgary, Canada, to the U.S. West Coast and Midwest (see figure 5-5).

The potential high market price of Alaskan gas and associated marketing problems have been the main cause for a lack of financing for completing

Figure 5-5.—The Alaska Natural Gas Transportation System


Prudhoe Bay
Mainline segments of the Alaska Natural Gas Transportation System Financed and "Prebuilt" on the basis of Canadian Natural Gas Imports.
Fairbanks
Dempster Lateral
Whitehorse
Foothills Pipe Lines (Yukon) Ltd.
Calgary
Canada
Pacific Gas Transmission
Northern Border Pipeline
Ottawa
Chicago
Washington
San Francisco
U.S.A.

SOURCE: Office of the Federal Inspector, Alaska Natural Gas Transportation System, Washington, D.C.

the ANGTS. Current cost estimates of finishing the ANGTS are $40 to $50 billion, with the Alaskan segment alone estimated at $25 to $30 billion.[7] The tariff which would be charged to cover the costs of building the pipeline makes the projected price of Alaskan gas uncompetitive in its designated markets, in the short term. Estimates of the delivered price of Alaskan gas in 1989-90 are about $7.50 per thousand cubic feet, above the projected price of about $6.00 per thousand cubic feet for lower 48 gas in 1990.[8]

Alternative proposals to ANGTS include using Alaskan natural gas as raw material for a petrochemical facility or a methanol industry, or converting it to liquefied natural gas (LNG) for export to Japan. However, depressed world energy prices, marketing problems, limitations on Alaskan gas exports, and government commitments to ANGTS make these proposals unlikely alternatives to the pipeline system. A substantial increase in real gas prices may make the ANGTS or another Alaskan natural gas project economically feasible. A market outlet could be provided for natural gas now being produced, and reinjected, on Alaska's North Slope. In addition, the availability of natural gas processing and transportation infrastructure could improve the profitability of Alaskan offshore oil and gas development projects.

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[7] Stephen Eule and S. Fred Singer, "Export of Alaskan Oil and Gas," (New York: Universe Books, 1984), p. 140.

[8] General Accounting Office, "Issues Facing the Future Use of Alaskan North Slope Natural Gas" (Washington, DC, 1983), pp. 16-19.

Chapter 6

Federal Leasing Policies

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Chapter 6
Federal Leasing Policies

OVERVIEW

The Federal Government is the largest single owner of energy resource lands in the United States. It controls approximately 730 million acres onshore—mostly in western States—and nearly 1.9 billion acres in the offshore U.S. Exclusive Economic Zone (EEZ). Industry access to the vast government landholdings for oil and gas development is essential to meeting the country's future energy needs. However, energy development on Federal lands must be balanced with other land uses and with protection of the environment.

Federal leasing of offshore areas for oil and gas development is conducted under the Outer Continental Shelf (OCS) Lands Act of 1953, as amended in 1978. The 1978 amendments to the Act require that offshore leasing balance expeditious energy development with the interests of the coastal States and environmental concerns. The first Federal offshore lease sale was held in the Central Gulf of Mexico in October 1954. Leasing in the more hostile environments of the Arctic began in 1979 and in the deepwater areas of the lower 48 States in 1981.

At the same time that leasing in offshore frontier areas was growing, the rate of leasing was greatly accelerated. In the 1980s, the Department of the Interior implemented a system of "area-wide leasing," expanding the offshore acreage considered for each lease sale. Interior also increased the number of lease sales held each year. Opposition to the accelerated leasing schedule from coastal States, environmental groups, and others resulted in several delays to the lease schedule and some modification of the area-wide leasing approach.

Delays in the leasing schedule also resulted from the continuing dispute between the coastal States and the Federal Government over the appropriate division of power and revenues in offshore leasing. Although the controversies have primarily concerned issues in nearshore leasing—means of mitigating adverse effects on coastal areas and methods of dividing revenues from oil and gas basins crossing State/Federal boundaries—they have created uncertainty in frontier-area leasing as well. The extent of leasing in offshore frontier areas has also been constrained by deferrals of offshore acreage for military uses and controversies regarding international boundaries.

Some changes have been made in Federal leasing policy in recognition of the increased costs and risks of oil and gas development in offshore frontier areas. The primary lease term has been extended from 5 to 10 years and royalties have been lowered for most frontier areas. However, additional changes may be needed in bidding systems, the size of the lease tracts, and other leasing terms and conditions to provide the incentive for comprehensive exploration and development of the energy resources of Arctic and deepwater frontiers.

RATE AND EXTENT OF OFFSHORE LEASING

Background

Federal leasing of offshore areas for oil and gas development began soon after the passage of the OCS Lands Act of 1953,[1] but the petroleum industry had been developing oil and gas resources offshore for many years prior to that under State leases and permits. Offshore oil was first produced from piers off Summerland, California in 1896. The States of Louisiana, California, and Texas began leasing in the 1920s. The first Federal offshore lease sale was held in the Central Gulf of Mexico in October 1954.

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[1] Pub. Law 83-212, 67 Stat. 462 (1953), 43 USC 1331-1356.

The OCS Lands Act of 1953 provided the basic policy for the development of offshore oil and gas resources under Federal jurisdiction. It authorized the Department of the Interior to lease these areas to private persons for development, and it established general guidelines for managing the leasing process and post-lease activities. In 1969, an oil well blowout in the Santa Barbara Channel off California increased public awareness of the environmental risks of offshore leasing. This concern was coupled with greater uncertainty about future U.S. energy supplies after the Arab oil embargo of 1973. In 1974, Congress began to amend the 1953 Act to address these concerns, which culminated in the enactment of the OCS Lands Act Amendments of 1978.[2]

The 1978 Amendments made fundamental and somewhat controversial changes in offshore leasing policy. The Amendments opened up the decisionmaking process for offshore leasing to give affected parties—primarily the coastal States—the opportunity for greater involvement. Stricter criteria and standards were included in consideration of environmental factors and competing land uses. New emphasis was placed on the public revenue from OCS development and the receipt of fair market value for oil and gas resources. From 1978 on, Federal offshore leasing for oil and gas development had to balance energy policy goals with State, environmental, and revenue considerations.

In addition, the OCS Lands Act Amendments introduced the requirement for a 5-year schedule of proposed lease sales.[3] The June 1979 leasing schedule, which was revised in June 1980, was the first prepared in accordance with the requirement. This schedule increased the number of sales to be held in frontier areas; approximately one-half of the sales were scheduled for Alaskan and deepwater regions. In October 1981, however, the U.S. Court of Appeals ruled that the leasing program did not meet the requirements of Section 18 of the OCS Lands Act Amendments and remanded the program to the Secretary of the Interior for revision.

A 5-year leasing program drafted by the new Secretary of the Interior, James Watt, in mid-1981 did subsequently withstand the legal challenge for adequacy.[4] This program, which covered the period August 1982 through June 1987, proposed dramatic increases in the acreage to be offered and leased in an effort to increase domestic energy production. Approximately one billion acres of Federal offshore lands were to be offered for lease in the 5-year period. This was far more than the 50 million acres offered for lease in the entire period from October 1954 through June 1982. Under the new concept of "area-wide leasing," the acreage offered was increased from a previous average of 1 to 2 million acres per sale to 20 to 50 million acres per sale. In addition, the leasing schedule itself was accelerated to an average of eight sales per year, compared to an average of five sales per year in the previous 5-year period.

Most of the land to be leased under the 1982-87 schedule was in the frontier areas. Out of a total of 41 lease sales, there would be 16 offerings off Alaska, 12 in the Gulf of Mexico, 8 off the Atlantic Coast, 4 off California, and one reoffering sale. Several new Alaskan offshore areas would be opened to leasing for the first time. In total, over 56 percent of the acreage to be offered was off the Alaskan coast and another 20 percent was in the deepwater areas of the Gulf of Mexico, the Atlantic, and the Pacific.

Early opposition to the 1982-87 accelerated leasing program caused a number of delays in its implementation. Of the 21 lease sales scheduled through the end of 1984, only seven were held on the originally scheduled date. Opponents, mostly coastal States and environmental groups, challenged several sales with litigation on the basis of alleged violation of the requirements of the OCS Lands Act Amendments, the Coastal Zone Management Act, and relevant environmental laws. In addition to that opposition, Congress delayed sales by prohibiting the use of appropriated Interior Department funds for leasing and development of specific OCS basins in the Pacific, Atlantic, and Gulf of Mexico. However, of the lease sales scheduled for 1982-84, all but four—the two Georges Bank sales in the North Atlantic and two Alaskan sales—had been held by the end of 1984.

In 1983 and 1984, record amounts of OCS acreage were offered and leased. For the first time, substantial acreage was leased in Alaska—in the Diapir Field, and the Navarin, Norton and St. George Basins—and in the deepwater areas off the lower

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[2] Pub. Law 95-372, 92 Stat. 629 (1978), 43 USC 1801-1866.

[3] Section 18, Supra note 1.

[4] California v. Watt, No. 80-1894 (D.C. Cir. 1983).

48 States. In the Gulf of Mexico area-wide lease sales of 1983-84, more than 26 percent of the tracts leased were in water depths beyond 2,000 feet and 18 percent in water depths beyond 3,900 feet. Prior to 1983, leasing in water depths beyond 2,000 feet rarely exceeded 5 percent of the total acreage. Similarly, new deepwater acreage was leased in the Atlantic and Pacific regions.

In January 1984, the new Secretary of the Interior, William Clark, announced his intention to decrease the acreage considered for leasing under the 1982-87 leasing schedule because of State and environmental concerns. However, Secretary Clark continued to support the general concept of area-wide leasing, particularly in the Gulf of Mexico. A revised leasing schedule issued in October 1984 indicated that the six Gulf of Mexico area-wide lease sales to be held between May 1985 and April 1987 would take place as scheduled (see table 6-1). Several of the remaining Alaskan, California, and Atlantic sales, however, were delayed and some were reduced in acreage. Despite these modifications to the leasing schedule, the magnitude and

Table 6-1.—Five-Year OCS Leasing Schedule (8/82-6/87)

Region	Sale #	Location	Schedule date Original	 Current
Re-offering	RS-2	AT,CA,AK	Aug 1982	As scheduled
Alaska	71	Diapir Field	Sept 1982	Oct 1982
Atlantic	52	Georges Bank	Oct 1982	Postponed
Gulf of Mexico	69-1	Texas, LA	Oct 1982	Nov 1982
	69-2	MS,AL,FL	Oct 1982	Mar 1983
Alaska	57	Norton Basin	Nov 1982	Mar 1983
Alaska	70	St. George Basin	Feb 1983	Apr 1983
Atlantic	76	Mid-Atlantic	Apr 1983	As scheduled
Gulf of Mexico	72	Central Gulf	May 1983	As scheduled
Atlantic	78	South Atlantic	July 1983	As scheduled
Gulf of Mexico	74	Western Gulf	Aug 1983	As scheduled
Pacific	73	Central CA	Sept 1983	Dec 1983
Gulf of Mexico	79	Eastern Gulf	Nov 1983	Jan 1984
Pacific	80	Southern CA	Jan 1984	Oct 1984
Atlantic	82	North Atlantic	Feb 1984	Postponed
Alaska	83	Navarin	Mar 1984	Apr 1984
Gulf of Mexico	81	Central Gulf	Apr 1984	As scheduled
Alaska	87	Diapir Field	June 1984	Aug 1984
Gulf of Mexico	84	Western Gulf	July 1984	As scheduled
Alaska	88	Gulf/Cook Inlet	Oct 1984	Postponed
Alaska	89	St. George Basin	Dec 1984	Sept 1985
Atlantic	90	South Atlantic	Jan 1985	Postponed
Alaska	85	Barrow Arch	Feb 1985	Postponed
Alaska	92	N. Aleutian Basin	Apr 1985	Dec 1985
Gulf of Mexico	98	Central Gulf	May 1985	As scheduled
Atlantic	111	Mid-Atlantic	June 1985	Oct 1985
Gulf of Mexico	102	Western Gulf	Aug 1985	As scheduled
Pacific	91	Cent/North CA	Sept 1985	Dec 1987
Alaska	100	Norton Basin	Oct 1985	Dec 1985
Gulf of Mexico	94	Eastern Gulf	Nov 1985	As scheduled
Pacific	95	Southern CA	Jan 1986	Apr 1987
Atlantic	96	North Atlantic	Feb 1986	Nov 1987
Alaska	107	Navarin Basin	Mar 1986	Sept 1986
Gulf of Mexico	104	Central Gulf	Apr 1986	As scheduled
Alaska	97	Diapir Field	June 1986	Dec 1986
Gulf of Mexico	105	Western Gulf	July 1986	As scheduled
Alaska	99	Kodiak	Oct 1986	Postponed
Alaska	101	St. George Basin	Dec 1986	July 1988
Atlantic	108	South Atlantic	Jan 1987	July 1989
Alaska	109	Barrow Arch	Feb 1987	May 1987
Gulf of Mexico	110	Central Gulf	Apr 1987	As scheduled
Alaska	86	Shumagin	June 1987	Dec 1987

SOURCE: Minerals Management Service, 1985.

pace of OCS lease sales, still set at seven to eight per year, remain significantly greater than previous schedules.

The Department of the Interior is now soliciting comments from industry, coastal States and other interested parties on a new 5-year OCS Leasing Program for the period mid-1986 through mid-1991. The overlap between the two schedules in 1986/87 is intended to provide a transition period from one program to the next. Eleven sales have been carried over from the previous 5-year leasing schedule (see box).[5]

The new 5-year leasing schedule proposes a total of 43 sales: 33 standard sales, 5 frontier exploration sales, and 5 supplemental sales. The frontier exploration sales are scheduled for areas of Alaska where resource assessment is incomplete and in-

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[5] Department of the Interior News Release, "Secretary Hodel Releases Draft Proposed OCS Oil and Gas Program," (Mar. 21, 1985).

Proposed Five-Year OCS Leasing Schedule (7/86-6/91)

Region	Sale #	Location	Proposed date
Gulf of Mexico	105	Western Gulf	July 1986
Supplemental 1			Aug. 1986
Alaska	107	Navarin Basin	Sept. 1986
Alaska	97	Beaufort Sea	Dec. 1986
Pacific	95	Southern California	Apr. 1987
Gulf of Mexico	110	Central Gulf	Apr. 1987
Alaska	109	Chukchi Sea	May 1987
Gulf of Mexico		Western Gulf	Aug. 1987
Supplemental 2			Aug. 1987
Atlantic	96	North Atlantic	Nov. 1987
Alaska	86	Shumagin	Dec. 1987
Pacific	91	Northern California	Dec. 1987
Gulf of Mexico		Central Gulf	Feb. 1988
Alaska[a]		Gulf of Alaska	Mar. 1988
Gulf of Mexico		Eastern Gulf	May 1988
Alaska	101	St. George Basin	July 1988
Gulf of Mexico		Western Gulf	Aug. 1988
Supplemental 3			Aug. 1988
Atlantic		Mid-Atlantic	Oct. 1988
Alaska		North Aleutian Basin	Dec. 1988
Gulf of Mexico		Central Gulf	Feb. 1989
Alaska		Norton Basin	Mar. 1989
Pacific		Central California	May 1989
Atlantic	108	South Atlantic	July 1989
Gulf of Mexico		Western Gulf	Aug. 1989
Supplemental 4			Aug. 1989
Alaska		Navarin Basin	Sept. 1989
Alaska		Beaufort Sea	Dec. 1989
Gulf of Mexico		Central Gulf	Feb. 1990
Alaska		Chukchi Sea	Mar. 1990
Pacific		Southern California	Apr. 1990
Alaska[a]		Cook Inlet	June 1990
Gulf of Mexico		Western Gulf	Aug. 1990
Supplemental 5			Aug. 1990
Alaska[a]		Shumagin	Sept. 1990
Atlantic		North Atlantic	Oct. 1990
Pacific		Northern California	Dec. 1990
Alaska[a]		Kodiak	Jan. 1991
Gulf of Mexico		Central Gulf	Feb. 1991
Alaska		St. George Basin	Apr. 1991
Pacific		Washington-Oregon	Apr. 1991
Gulf of Mexico		Eastern Gulf	May 1991
Alaska[a]		Hope Basin	June 1991

[a] Frontier exploration sales.

Supplemental sales—Annual sales for selected drainage, development, and/or rejected bid blocks outside the Central and Western Gulf of Mexico.

SOURCE: Department of the Interior News Release, Mar. 21, 1985.

dustry interest appears to be low. An added presale step, a Request for Interest, will be used prior to these sales to determine if industry interest warrants holding the sales. The supplemental sales will be held in August of each year for selected drainage, development, and/or rejected bid blocks outside the Central and Western Gulf of Mexico.

Annual lease sales will still be held in the two most prospective areas: the Central and Western Gulf of Mexico. Outside of these areas, the pace of leasing will be slowed from one sale every 2 years to one sale every 3 years. In addition, a "flexibility provision" has been added to allow the pace of leasing to be adjusted to economic conditions. Sales in certain areas (Northern, Central, and Southern California; Eastern Gulf of Mexico; Navarin Basin; Beaufort Sea; North Aleutian Basin; and St. George Basin) may be accelerated if changes in oil prices or new geologic data warrant.

Area-Wide Leasing

The area-wide leasing system made fundamental changes in the lease tract offering process. Prior to 1983, under what is called the "tract nomination" sale system, the Department of the Interior offered a limited number of specific tracts for leasing based on the geological prospects for oil and gas as interpreted by the government. Between the first offering of offshore leases under the OCS Lands Act Amendments in February 1979 and the beginning of the area-wide sale system in April 1983, about 23 million acres were offered for leasing.

Under area-wide leasing, the Department of the Interior offers an entire lease sale planning area for leasing. Tracts may be selected from every unleased tract and from tracts where the leases have expired. Recommendations are still made by the States and other Federal agencies for exlusion of tracts from the sale. But under this system, industry is permitted to choose where its investments in exploration will be made without being double-guessed by the Department of the Interior.

About 546 million acres have been considered by the industry in the 11 area-wide lease sales held through the end of 1984. This is actually an overestimate, because it includes blocks previously sold as well as double-counting for 35 million acres offered twice in the Gulf of Mexico. About 63 percent of this or 346 million acres was actually offered for leasing in the area-wide sales. Of this, industry leased 13 million acres. Based on these numbers, area-wide leasing is a misnomer. The system should more accurately be called "area-wide consideration" or "area-wide selection."

In theory, area-wide leasing was adopted to provide the industry an opportunity for early selection of tracts which offer the best prospects for discovery of oil and gas. In operation, it also has resulted in an increased rate of leasing. Industry faulted the tract nomination system because the Department of the Interior made its own determinations of resource potential and often failed to include many of the tracts nominated by industry. However, critics of the area-wide system maintain that a return to a nomination system where the Department of the Interior assures that industry nomination will be honored would allow sufficient freedom of tract selection.

Under revised area-wide leasing procedures announced by Secretary of the Interior William Clark in January 1984, firms make specific recommendations on selected tracts at the call for information stage (the initial phase of the leasing process). Secretary Clark requested that the industry target those tracts in which they are seriously interested and reduce "scenery" selections (those intended to mask bidding strategy). In this way, environmental assessment can be focused on specific areas of interest to the industry. Better information can also be provided to State and local governments and environmental groups early in the area identification process so that they may prepare for the later consultation phase.

Secretary of the Interior Don Hodel adopted a modified area-wide leasing system for use during the 1986-91 5-year leasing schedule. Although essentially the same as the Clark system, it is here called the "focused approach" intended to focus lease offerings on promising acreage.

Both the industry and the Department of the Interior defend the concept of area-wide leasing, noting that the United Kingdom and Canada have successfully used this approach for offshore leasing for a number of years. From the standpoint of technology development, the industry also asserts that expensive offshore technologies will only be developed and financed if the industry has profitable leases.

The shift from tract nomination to area-wide leasing has raised opposition from some coastal States and environmental groups, which allege that area-wide leasing is nothing more than a "fire sale" and giveaway of the Nation's resources and, because of the magnitude of the sales, a threat to the ocean and coastal environments. The industry, however, defends the integrity of the area-wide approach in terms of efficient resource development, fair value received for Federal leases, and environmental protection. The Minerals Management Service (MMS) also denies that the environment is receiving any less attention under the area-wide leasing system than under the tract nomination approach.

The area-wide leasing debate has focused largely on the Gulf of Mexico. About 70 percent of the acreage offered under the area-wide system through January 1985 has been in that region. Less attention has been given to the potential impact and effectiveness of area-wide leasing in deepwater and Arctic frontier regions because of limited experience with leasing in these areas. The Gulf of Mexico, being a mature producing region where the geology and petroleum prospects may be estimated more accurately, is considerably different from frontier regions where little or no production has occurred and where each new well is considered a wildcat. Analysis of the results of area-wide leasing in the frontier areas is difficult because few area-wide sales have been held in these regions.

Those critical of area-wide leasing have emphasized two aspects of public policy: 1) receipt of fair market value for government-owned resources; and 2) environmental implications of an accelerated, broad-based leasing program.

Fair Market Value Concerns

The OCS Lands Act Amendments of 1978 require that the government receive fair market value for offshore leases, although no precise definition of fair market value is given. Controversy has resulted from the fact that the average bonus bid per acre has declined under the area-wide system, and that fair market value may not be received for leases under area-wide offerings. The average bid per acre under the tract nomination system between 1979 and 1983 was $2,388. Since the beginning of area-wide leasing in 1983, bonus bids have averaged about $529 per acre.

The debate over the receipt of fair market value under area-wide leasing has centered on economic analyses done by National Economic Research Associates, Inc. (NERA) for the State of Texas in support of the State's discussions with the Department of the Interior over disposition of escrow money from Federal/State tracts in the Gulf of Mexico.[6] NERA's analysis attributed the reduced bonus bids received in area-wide lease sales in the Gulf of Mexico to several factors:

- *Supply and Demand*: Based on classical economic theory of supply and demand, the more tracts offered in a lease sale, the lower the bids will be as a result of less competition.
- *Fixed Budgets*: If firms have fixed budgets for lease acquistion, they will tend to bid lower on a larger number tracts offered in an area-wide sale than they would if fewer tracts were offered in a nomination sale.
- *Bargain Hunting*: If firms can acquire leases cheaply, they will be willing to accept higher risks of dry holes.
- *Time Value of Money*: If production may be delayed, firms will reduce their bids to offset the cost of discounting the investment.

> The NERA study concluded that area-wide leasing will not accelerate energy production, because development is determined by the profitability of individual leases and not the rate and number of lease purchases.

In conducting its analysis, NERA also found that water depth had little relationship to the lower bids received in the Gulf of Mexico. NERA did not undertake an analysis of data relating bids to tract depths, but rather related bid levels to distance from shore. Distance from shore and water depth are generally, but not consistently, related. By assuming a one-to-one relationship between distance offshore and water depth, the NERA study may have masked the true effects of water depth on bid levels. An OTA analysis of bonus bids and water depth in five area-wide leases sales in the Gulf of Mexico suggests that a trend relationship may exist between lower bonus bids and leases in water depths of 600 feet and greater (see figure 6-1). Bids in deepwater frontier areas may be lower as a result of the increased risks and higher costs associated with exploration and development of oil and gas.

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[6] Letter and attachments from Governor Mark White to Secretary of the Interior William Clark (May 25, 1984) and affidavit and exhibits of Jeffery J. Leitzinger, Senior Consultant, National Economic Research Associates, Inc.

The lower bids in the Gulf of Mexico area-wide lease sales may also be due to a number of other factors. These include pessimism over future oil prices; the failure of the industry to find oil and gas in highly prospective areas of the Atlantic and Pacific; the fact that the leased tracts in the Gulf of Mexico had been "picked over" previously; and the increase in the minimum bid from $25 to $250 per acre by the Department of the Interior.[7] In addition, it has been pointed out that the downward trend in bids in the Gulf of Mexico actually began under the tract nomination system in 1980 and continued under the area-wide system (see figure 6-2).

In general, fair market value is a difficult concept to define. The U.S. Court of Appeals upheld the accelerated leasing program of the Department of the Interior, noting that the law does not require the maximization of revenues, only the receipt of a fair return for Federal leases. The Department of the Interior points out that bonus payments represent only about one-fourth of the revenues received from offshore oil and gas leases and thus are not the only consideration in assessing fair market value. Federal payments are also received in the form of taxes, royalties, and rentals.

Environmental Concerns

Environmental concerns related to area-wide leasing focus on the inability of the States and the Federal Government to evaluate potential environmental impacts from offshore development in lease

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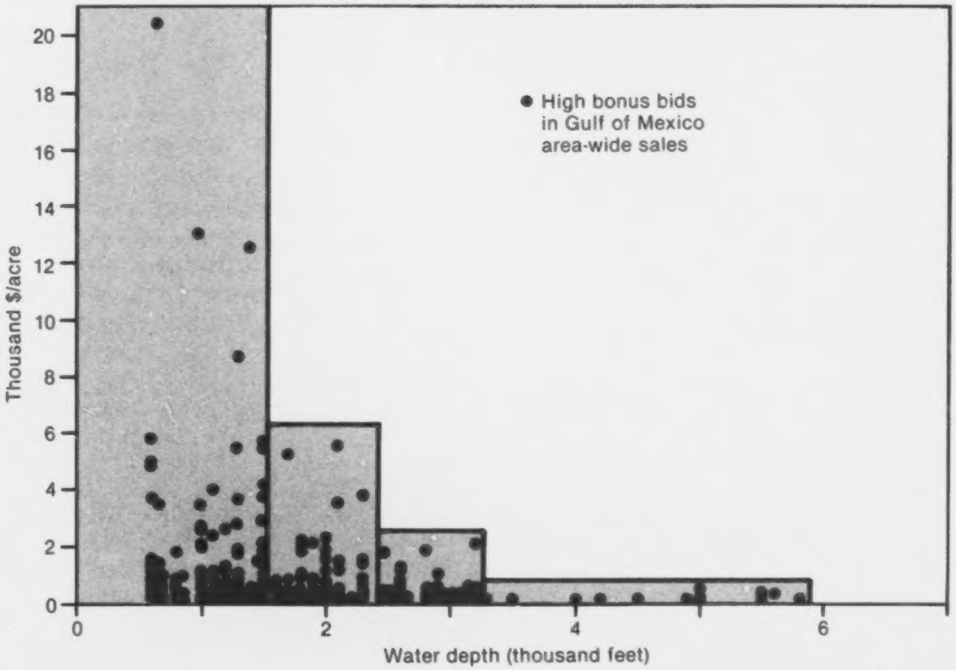
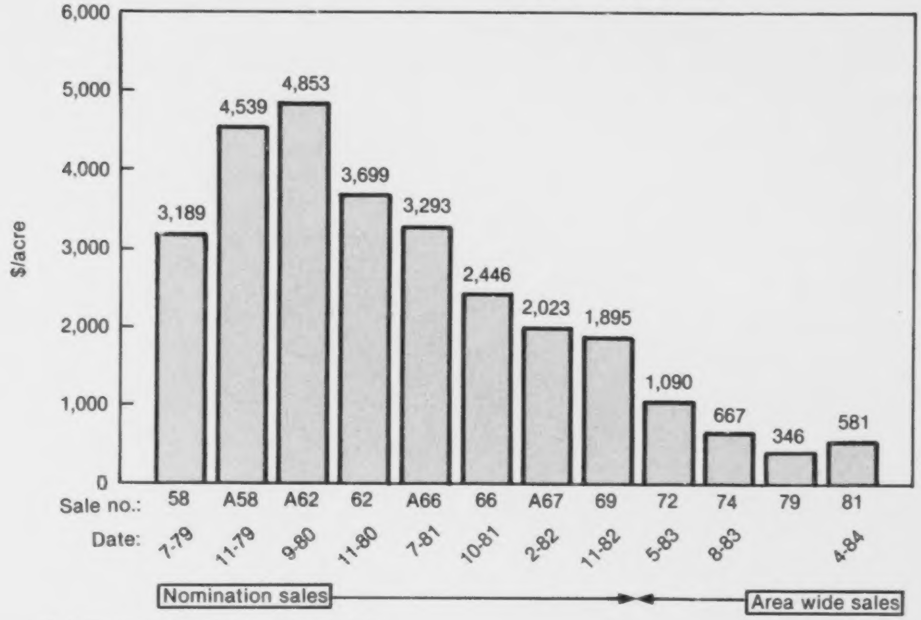
[7] National Ocean Industries, *Area-Wide Leasing: National Boon or Industry Boondoggle?*, (Washington, DC: 1984).

Figure 6-1.—Gulf of Mexico Bidding by Water Depth



SOURCE: Office of Technology Assessment.

Figure 6-2.—Trends in Gulf of Mexico Average Bids



SOURCE: National Ocean Industries Association.

sales covering broad, diverse areas. It may be difficult for State and local governments to plan for and assess the impacts of OCS development under area-wide leasing because of the extent of the area considered and the uncertainty of which portions will be offered for sale. In addition, environmental groups assert that general statements of environmental impacts are not useful,and detailed analyses of vast areas that will not be leased is wasteful.[8]

The Department of the Interior stresses that prelease and post-lease environmental regulations and State and local consultation are the same under area-wide leasing as under the tract nomination system. The steps and procedures required by law to identify, assess, and disclose possible environmental impacts which may result from offshore oil and gas development are being followed. The industry believes that environmental assessments under area-wide leasing are better. Consideration of larger areas may lead to a broader knowledge of geohazards, marine biology, physical oceanography, and environmental baselines.

Environmental information, however, is but one factor considered by the Secretary of the Interior in a leasing decision. Environmental interests argue that mere *pro forma* adherence to legal requirements is not sufficient. Environmental information should also be adequately considered by the Secretary in the decision process. Environmentalists maintain that the Secretary of the Interior is not assigning appropriate weight to environmental risks in balancing OCS oil and gas development with possibilities of environmental harm.

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[8] Department of the Interior, *Final Supplement to the Final Environmental Statement*, Vol. 2, Comments from Industry and Public Interest Groups (Fall 1981).

THE ROLE OF THE COASTAL STATES

Background

Ownership of offshore oil and gas resources has been the source of major disagreements between the Federal Government and the coastal States for nearly 50 years. Realizing the extent of the petroleum wealth that lay below the seabed off their shores, California, Louisiana and Texas began asserting their rights of ownership to the submerged lands as early as 1937. The spat between the States and the Federal Government over offshore petroleum resources became known as the "Tidelands Issue." This issue figured prominently in the politics of that era and influenced Federal-State relationships for nearly two decades. Even today, the struggle continues over the appropriate balance of power, authority, and revenue entitlements that coastal States should exercise over resources in the Federal portion of the Continental Shelf.

Prior to 1945, the seabed resources beyond the internationally recognized 3-mile Territorial Sea were not owned by any nation or individual in accordance with customary international law at that time. On September 28, 1945, President Harry S Truman by Executive Proclamation declared that the United States has exclusive control and jurisdiction over the natural resources of the seabed and subsoil of the Continental Shelf adjacent to the United States.[9] This unilateral claim to the resources of the Continental Shelf was not recognized under international law until it was ratified by the First Law of the Sea Conference held in Geneva in 1958. The Convention on the Continental Shelf recognized that a coastal nation "exercises over the Continental Shelf sovereign rights for the purpose of exploring it and exploiting its natural resouces."[10]

Between President Truman's proclamation in 1945 and international recognition of coastal nations' authority in 1958, intense disputes arose between the coastal States and the Federal Government over who had the authority to regulate development and who would benefit from the rich petroleum resources that lie beneath the seabed.

The judicial answer to the question of ownership and control of the resources of the Continental Shelf came in 1947 when the United States Supreme Court in *U.S. v. State of California* decided that the Federal Government and not California had "paramount rights" and power over the 3-mile Territorial Sea (recognized by international law at that time), including full dominion over the resources of the submerged lands.[11] In subsequent suits filed by Louisiana, Texas, and Florida the Court applied the same legal principle and awarded jurisdiction over the submerged lands to the Federal Government. The Court allowed some extended State claims in the Gulf of Mexico because of the special conditions under which Florida and Texas were admitted to the Union.[12]

Although the coastal States' legal challenge for control of offshore petroleum resources failed, a political assault in the Congress paid off. In 1953, Congress enacted the Submerged Lands Act, which effectively reversed the Supreme Court's decision in *U.S. v. State of California* by conveying all rights that the Federal Government claimed in the nearshore submerged lands to the coastal States.[13] It gave the States the title and ownership of the submerged lands and natural resources seaward of their coasts out to 3 nautical miles. With the contentious issue of State claims to the Continental Shelf resolved, the Congress simultaneously enacted the OCS Lands Act of 1953, which established Federal leasing authority in the OCS seaward of the State-controlled zone.

However, the conflict between the coastal States and the Federal Government over oil and gas beneath the seabed did not abate with the enactment of the Submerged Lands Act and the OCS Lands Act. Disagreements continued over drainage of oil from reservoirs beneath adjacent Federal and State properties, and the apportionment of revenues from oil in disputed areas. As the pace of offshore oil and gas development increased under the leasing procedures of the OCS Lands Act, coastal States voiced their concerns over the adverse environmental and social impacts that could result from operations off their shores.

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[9] Exec. Proclamation No. 2667; 59 Stat. 884 (1945).

[10] 15 UST 471; TIAS 5578.

[11] 332 US 19 (1947).

[12] *U.S. v. Louisiana*, 339 US 699 (1950); *U.S. v. Texas*, 339 U.S. 707 (1950).

[13] Public Law 83-31; 67 Stat. 29 (1953); 43 USC 1301-1315.

In response to concerns that unplanned development of the coastal region could lead to irreparable environmental damage, the Congress enacted the Coastal Zone Management Act (CZMA) in 1972. The CZMA authorized Federal grants to coastal States as incentives to establish coastal zone management plans. Once a State coastal zone management plan is approved by the Secretary of Commerce, all Federal actions within the coastal zone, or which "directly affect" the coastal zone, are required to be conducted in "a manner which is, to the maximum extent practicable, consistent with approved State management programs." In the past, coastal States have asserted that the act of offering offshore leases "directly affects" the coastal zone and that leases should be subject to a determination of consistency with the adjacent State's coastal zone management program. However, in 1984, the United States Supreme Court in *Secretary of the Interior v. California* held that OCS oil and gas lease sales *per se* are not Federal activities "directly" affecting the coastal zone within the meaning of the CZMA, and therefore do not require State consistency determinations at the time leases are offered.[14]

The CZMA was amended in 1976 to establish a Coastal Energy Impact Program (CEIP).[15] The CEIP was designed to provide States and local governments with financial assistance to meet needs resulting from energy activities in coastal regions, including the development of OCS oil and gas. Enactment of the CEIP was predicated on the belief that coastal States are likely to encounter greater impacts from energy development than inland States because of their geographic location with regard to offshore petroleum, ports for energy imports and exports, and electric power generating stations which require large volumes of cooling water. The CEIP, although scheduled to continue through 1986, has not been funded since 1980.

The OCS Lands Act of 1953, as amended in 1978, declares it national policy that:

> . . . the outer Continental Shelf is a vital national resource reserve held by the Federal Government for the public, which should be made available for expeditious and orderly development, subject to environmental safeguards, in a manner which is consistent with the maintenance of competition and other national needs; . . .[16]

Although the congressional statement of national policy emphasizes the importance of offshore petroleum reserves and acknowledges that they should "be made available for expeditious and orderly development," the Act concurrently recognizes that:

> . . . exploration, development, and production of the minerals of the outer Continental Shelf will have significant impacts on coastal and non-coastal areas of the coastal States . . .[17]

The Secretary of the Interior is therefore responsible for balancing what are sometimes conflicting national policies: providing for secure domestic sources of oil and gas from the OCS while at the same time protecting environmental values and respecting the plans, goals and objectives of sovereign coastal States and local governments.

In response to concerns about the potential impact of offshore petroleum development on the coastal States and local communities, Congress set forth as national policy in the 1978 Amendments the principles that: 1) States and local governments may require Federal assistance to protect their coastal zones; 2) States and local governments are entitled to participate in the policy and planning decisions of the Federal Government; 3) States and local governments have rights and responsibilities to protect the environment and the population from adverse impacts of offshore petroleum activities; and 4) the petroleum industry has the responsibility for ensuring the environmental and personal safety of offshore operations.

The OCS Lands Act as amended in 1978 is unique among Federal statutes which authorize leasing, sale or disposal of public resources. Much more State and public involvement in lease planning and Federal licensing and permitting is mandated in the administration of the OCS leasing program than is required for similar leasing of coal, onshore oil and gas, or other minerals on Federal lands. When considered in conjunction with the requirements of the CZMA, the National Environmental Policy Act of 1969, the Federal Water Pollution Control Act as amended, and the Clean Air Act, the OCS Lands Act provides an unprecedented opportunity for coastal State involvement in the offshore oil and gas leasing program.

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[14] Case No. 82-1326, (Decided Jan. 11, 1984).

[15] Public Law 94-370, 90 Stat. 1013 (1976).

[16] Section 3(3), Supra note 1.

[17] Section 3(4), Supra note 1.

The 1978 OCS Lands Act Amendments call for State and local government consultation, comments, or coordination at six separate points in the planning, leasing, exploration, and production-development sequence: 1) during the formulation of the 5-year leasing program; 2) at the time of review of environmental impact statements regarding the 5-year leasing program; 3) prior to a proposed lease sale; 4) with regard to oil and gas that may straddle adjoining Federal and State properties; 5) at the issuance of exploration permits; and 6) during the review of production and development plans. In addition, the Secretary of the Interior is directed to provide the necessary information to State and local governments to assist them in responding to Federal actions (see table 6-2).

At no point in a lease sale can a State absolutely veto lease planning or sale preparation. However, States can make recommendations through the consultation and commenting provisions. After leases are awarded, the coastal States have the power of approval of exploration and development plans, which must be consistent with their coastal zone management programs. Pipelines, ports, or storage and transfer facilities for supporting offshore oil and gas operations that are located within the 3-mile Territorial Sea or on the shore must also conform with a State's coastal zone management plans and other local zoning or land use laws within the police powers of the State. As a condition of Federal approval of a State coastal zone management program, provision must be made for giving adequate consideration to energy developments in the national interest of the United States.

Notwithstanding the ample provisions made in the OCS Lands Act and the CZMA for coordina-

Table 6-2.—State Role in Offshore Oil and Gas Leasing

Subject	Action	Authority
Outer Continental Shelf Leasing Program	State and local government comments on proposed 5-year plan and on Secretary's annual review of the plan.	OCSLA Sec. 18
Environmental Impacts	Comments by the State on draft environmental impact statements at time of revisions in the 5-year leasing program and at submission of exploration and development and production plans.	NEPA Sec. 102(D) OCSLA Sec. 25
Proposed Lease Sale	Coordination and consultation with State and local officials concerning size, timing or location of proposed lease sale.	OCSLA Sec. 19
Leasing Within 3 Miles of State's Territorial Sea	Consultation with regard to development of shared oil pools.	OCSLA Sec. 8(g)
Geological and Geophysical Exploration Plans	Certification of consistency with State coastal zone management plans.	OCSLA Sec. 11(c) CZMA Sec. 307(c)(3)
Production and Development Plans	Coordination and consultation with State and local officials and certification of consistency of production and development plans with the State coastal zone management program.	OCSLA Sec. 25 CZMA Sec. 307(c)(3)
OCS Oil and Gas Information	Secretary directed to provide information on proposed plans, reports, environmental impact statements, tract nominations, and other information, including privileged information in the custody of the Secretary.	OCSLA Sec. 26

SOURCE: Office of Technology Assessment.

tion and cooperation among Federal, State and local governments, a number of disagreements have arisen that add to the uncertainties facing the offshore oil and gas leasing program. These controversies contribute to contentious relationships between some coastal States and the Federal Government regarding offshore resource development. The failure of the Executive Branch to deal with these issues to the mutual satisfaction of the States and the Federal Government has prompted the Congress to seek legislative solutions.

Special State/Federal Problems

Coastal Zone Management Consistency

Coastal States consider the lease sale as a critical point in the OCS oil and gas development process. At this point, contractual obligations are assumed and property rights are conveyed to successful bidders. The States believe that the act of leasing is the beginning of a process that inextricably leads to exploration, and if commercial discoveries are made, to production and development by the lessees. For this reason, the States believe, lease sales themselves should be consistent with State coastal zone management programs.

The Department of the Interior insists that the act of leasing in Federal waters is not an action that "directly affects" the coastal zone. Only when physical activities, such as exploration, begin on a lease are there activities that "directly" affect the coastal States. Haggling over the consistency issue has resulted in several lawsuits that have delayed leasing decisions and introduced uncertainty in the leasing process for a decade.

In January 1984, the U.S. Supreme Court decided the question of whether a lease sale "directly affects" the coastal zone, and therefore whether the Secretary of the Interior must certify that the lease sale is consistent with an approved State coastal zone program. The case, *Secretary of the Interior v. California*[18] reversed the decision of the 9th Circuit Court of Appeals in *California v. Watt.*[19] In *Secretary of the Interior v. California,* the Supreme Court concluded in a 5-4 opinion that lease sales are not activities "directly affecting the coastal zone" within the meaning of the CZMA. The State's position with regard to the significance of the lease sale in the exploration and development sequence was dismissed by the Court as a policy argument that had previously been resolved by the Congress in enacting the legislation.

Response to the Supreme Court's decision came swiftly in the 98th Congress. Bills were introduced in both Houses of the Congress to overrule the decision, but laws have not been enacted.[20] These proposals would substitute the term "significantly affecting" for the term "directly affecting," which was judged by the court to exclude the Federal act of leasing OCS oil and gas. By substituting the term "significantly" for "directly," sponsors of the bills hoped to invoke the liberal interpretation of the term "significantly" that has been used by the Courts in interpreting the National Environmental Policy Act.

Revenue Sharing

The immense value of the oil and gas that lay below the seabed offshore the United States has been the crux of a long-term battle between the Federal Government and the coastal States over control of the so-called submerged lands. Although the Congress transferred ownership of the natural resources in coastal waters out to 3 nautical miles to the States in 1953, the States have never taken their eyes off the Federal revenues that have been garnered from leasing OCS oil and gas.

In the 30 years between 1953 and 1983, the Federal Government has received over $68 billion from offshore oil and gas leases. The coastal States claim that they are entitled to share in these proceeds because State and local governments endure fiscal, social and environmental impacts which result from increased oil and gas activity in the OCS. Coastal States support their arguments for revenue sharing by noting that inland western States with Federal lands within their borders share 50 percent of the proceeds received by the Federal Government for minerals development on such lands.[21] Equity, the coastal States claim, requires that the Federal Government similarly share offshore revenues with States adjoining the OCS. The Federal Government contends that, on balance, OCS development has a net positive effect on adjoining coastal States.

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[18] 78 L. Ed. 2d. 496; 52 USLW 4063 (1984).

[19] 683 F. 2d. 1253 (9th Circuit, 1982).

[20] H.R. 4589 and S. 2324, (98th Congress, 2d. sess., 1984).

[21] Mineral Lands Leasing Act, 30 USC 181 *et.seq.*

The coastal States increased their efforts to convince the Congress to enact an OCS revenue sharing bill when funding cutbacks for support of State coastal zone management programs were proposed at the same time that OCS oil and gas development was being accelerated and the National Sea Grant College Program[22] was zeroed by the Reagan Administration in fiscal year 1982. As a result, legislation was introduced in the 97th Congress (H.R. 5543) to establish an "ocean and coastal resources management and development fund" to be transferred to coastal States from OCS revenues. The bill passed the House of Representatives by a 260-134 vote in the 97th Congress, but no action was taken in the Senate.

An identical bill (H.R. 5) was introduced in the 98th Congress. Similar legislation has been introduced in the 99th Congress. The legislative proposals would set aside 10 percent of the OCS revenues in any fiscal year when revenues exceeded the amount received during fiscal year 1982 ($7.8 billion). It provided a cap of $300 million as the maximum amount that could be transferred to the fund in any year. All of the coastal States bordering on the ocean, plus those on the Great Lakes, the U.S. affiliated Caribbean Islands, Pacific Trust Territories, and U.S. protectorates in the Pacific Ocean would share in the fund. Money would be distributed from the fund as block grants.

States receiving these block grants would be required to spend specific proportions of the funds received for coastal zone management, mitigation of impacts from coastal energy development, and enhancement and management of living marine resources and other natural resources. The entitlement for each State would be determined by formulae based on the level of leasing adjacent to the State, volume of oil and gas produced from the adjacent OCS, proposed oil and gas lease sales to take place within the 5-year leasing program, coastal-related energy facilities located within each coastal State, shoreline mileage of the State, and coastal population of each State.

Similar legislation was introduced in the Senate, but the bills were not acted upon. The House of Representatives attached the provisions of H.R. 5 to a fisheries program authorization bill (Title I, S. 2463) and forwarded it to the Senate. The Senate rejected the House amendment which included provisions for ocean and coastal block grants and decided to resolve the disagreement in Conference Committee. The Senate receded from its demands to reject the block grant proposals and agreed to the House amendment with modifications. The House agreed to the conference report on S. 2463, but consideration by the Senate was delayed until the waning days of the 98th Congress. During the last days of the 98th Congress, in the face of concerted opposition by a number of Senators, the conference report was still pending when Congress adjourned.

The Administration opposed the revenue sharing proposals introduced in the 97th and 98th Congresses because of their impact on the Federal budget; the inclusion of territories, islands and States that would have no OCS development off their shores; and the earmarking of the use of the block grants for coastal zone management activities. In general, the offshore oil and gas industry supported the concept of revenue sharing with the hope that States which have a stake in the revenues from the OCS would be more receptive to offshore development.

OCS Escrow Funds

Drilling in Federal waters within 3 miles of the seaward limits of State waters contained within the Territorial Sea stands a risk of tapping a common pool of oil that straddles the Federal/State boundary. Section 8(g) of the OCS Lands Act provides for agreements between the Secretary of the Interior and the Governors of affected States to apportion the proceeds of oil and gas removed from the Federal side of the border area. If agreement is not reached between the State and the Secretary within 90 days after an announced sale, the Department of the Interior may proceed with the lease sale providing all revenues received from the sale are placed in escrow pending agreement between the parties on apportioning the monies. In the absence of mutual agreement, Federal Courts may be called on to decide the equitable division of the money.

Nearly $5.4 billion has accrued in the escrow account to date. The States of Texas, Alaska,

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[22] National Sea Grant Program (1966), 33 USC 1121-1124.

Mississippi, Florida, California, Louisiana, and Alabama are scheduled to share the escrow money with the Federal Government. Negotiations over the apportionment of the escrow funds have proceeded intermittantly between the States and the Department of the Interior.

As a result of the sharp disagreement over the States' share of the escrow fund, opposition to areawide leasing in the Gulf of Mexico is building in States that have up to now enthusiastically supported offshore oil and gas development. Both Louisiana and Texas filed lawsuits in early 1984, and Alaska joined them in December 1984. In August 1984, Secretary of the Interior William Clark offered non-litigating States an arrangement which included 16⅔ share of bonus and rental receipts. The States are seeking a larger share of the escrow funds plus an acceptable share of future income (e.g., royalties) from these tracts.

Congressional Leasing Moratoria

The Department of the Interior has been prohibited by Congress from offering certain areas in portions of the North Atlantic, Central and Northern California, Southern California, and Eastern Gulf of Mexico planning areas during fiscal years 1982-85. Congress placed restrictions in the annual Interior appropriations acts on spending funds for the purpose of pre-lease preparation or holding certain lease sales.

In fiscal year 1982, 736,000 acres were placed under a moratorium in Sale 53 in the Central and Northern California lease area. In fiscal year 1983, the moratorium was expanded to include 35 million acres off California and New Jersey. In fiscal year 1984, 53 million acres were placed under a moratorium. This included 8.7 million acres in Georges Bank in the North Atlantic, 35 million acres in Central and Northern California, 1.6 million acres in Southern California, and 7.7 million acres in the Eastern Gulf of Mexico.[23] In fiscal year 1985, moratoria were continued on the same sales with the exception of the Eastern Gulf of Mexico. Secretary of the Interior William Clark assured Congress that the Eastern Gulf of Mexico would not be leased until problems with the Department of Defense and the State of Florida are resolved. About 45 million acres of the OCS are currently under congressional moratoria.

The moratoria appear to have resulted from a combination of several factors: 1) they were partly a political response to the intractable approach of former Secretary of the Interior James Watt toward placing one billion acres of OCS up for sale; 2) Members of Congress shared the frustration of the coastal States with the reduction in funds for coastal zone management and Sea Grant College programs; 3) coastal States and environmental groups continued to disagree with the MMS over tract deletions and cancellation of pending OCS sales; 4) the Administration continued to oppose sharing offshore revenues with coastal States; 5) the Department of the Interior and the States failed to reach agreement on division of escrow revenues from drainage tracts; and 6) Department of Defense pressure to force agreement with the MMS on deferrals or deletions of lease tracts for military and national defense uses may have prompted some Members to support the moratoria.

Several authorization bills were introduced in the 98th Congress which also would have imposed legislative moratoria on OCS leasing and exploration and development of offshore California and New England.[24] None of these bills were enacted. However, action within the House Committee on Appropriations Subcommittee on the Department of the Interior and Related Agencies achieved the same objective through the less-visible appropriations process.

The Department of the Interior has objected to the imposition of congressional moratoria, but to little avail. Factions within State and local governments and environmental groups have supported the leasing moratoria. The offshore industry actively opposes any moratoria. The industry cites its outstanding environmental safety record and the national need for secure domestic energy resources as reasons why current leasing moratoria should be lifted.

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[23] Public Law 98-146.

[24] S. 760, H.R. 2059, S. 1103, H.R. 2581. (98th Congress, 1st. and 2nd. sessions 1983-1984).

MILITARY OPERATIONS

Military strength and dependable energy supplies are considered to be the foundations of U.S. national security. Recognizing this fact, the Department of Defense has indicated its support for expediting exploration and development of the energy resources in the OCS. However, as offshore oil and gas development expanded since 1953, there was greater interaction between military use of sea space and the offshore petroleum activities. As OCS development pushed further seaward into deeper waters and expanded into frontier regions, the incidents of encounters, interference, and incompatibility between the two uses of the ocean became more numerous.[25]

Conflicts between offshore oil and gas uses and military uses will probably increase in the future. The Department of the Interior accelerated the rate and extent of leasing in the OCS as a means to hasten the exploration and development of offshore oil and gas beneath the seabed. At the same time, military exercises and activities offshore have increased in response to greater emphasis on military preparedness. With the advent of sophisticated electronic equipment for both military and industrial use, there may be potential for electromagnetic interference which could present yet another hazard in addition to physical interference.

Agreements between the Department of Defense and MMS over deferrals and exclusions of lease tracts for military reasons historically have been negotiated quietly with little fanfare. Disagreements between the agencies were well hidden. However, what was once handled on a routine case-by-case basis seems now to be turning into a problem too broad and complex to be dealt with *ad hoc*. The most recent indication of this is the provision in the Department of Defense Authorization Act of 1984 that directs the Secretary of the Navy to inform the Congress of the potential effects of offshore oil and gas operations on naval operations and to define offshore zones where oil and gas drilling could cause appreciable impacts on naval operations.[26]

The Navy transmitted the information required in the 1984 Defense Authorization Act to the Congress on May 29, 1984.[27] In the memorandum, the Navy identified six operational areas with potential for conflicts between military operations and offshore oil and gas development. Air Force and NASA operations were also included in the Navy's response. The identified activities include: 1) submarine transit lanes in the North Atlantic area; 2) fleet operations, missile flights, and high-performance aircraft testing, as well as classified uses in the Mid-Atlantic lease area; 3) submarine transit lanes, ballistic missile testing ranges, and sonar testing as well as the NASA Cape Canaveral launch range in the South Atlantic area; 4) aircraft carrier flight operations, flight training, air-to-surface missile testing, and equipment testing in the Eastern and part of the Western Gulf of Mexico areas; 5) fleet operations, missile testing, testing of submarine electronic systems, submarine transit lanes, and gunnery training in the Central, Northern, and Southern California areas; and 6) classified uses of an unspecified nature in part of one Alaskan planning area. In addition, underwater listening posts which probably require protection from industrial interference are located on the Continental Shelf offshore both the Atlantic and Pacific Coasts and adjacent to Alaska.

MMS and the Department of Defense have taken steps to minimize offshore conflicts in the military and NASA operating areas. Since 1979, between 40 and 55 million acres have been set aside or deferred from OCS leasing, and perhaps as much as 75 million additional acres may be leased only with operating restrictions included to protect military interests[28] (see figure 6-3). Estimates of acreage affected by military operations should probably be

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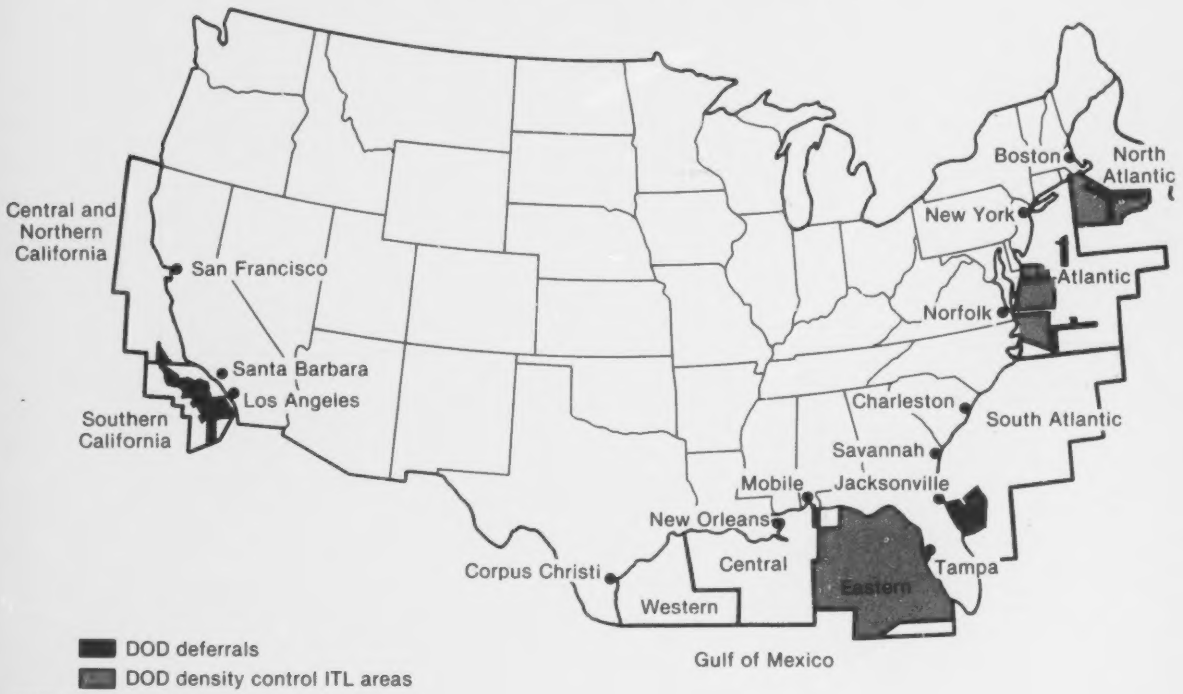
[25] For a history of conflicts between the military and the oil industry in the offshore areas see, Norman Breckner et. al., *The Navy and the Common Sea*, (Washington, DC: Office of Naval Research, 1972).

[26] Public Law 98-94, Section 1260 (Sept. 24, 1984).

[27] Letter of transmittal from Under Secretary of the Navy James F. Goodrich to the President of the Senate George Bush, with enclosures (May 29, 1984).

[28] The exact acreage which are subject to military operating restrictions is not available from MMS. About 42 million acres in the Eastern Gulf of Mexico lease planning area is subject to density controls and military clearance. Approximate acreage subject to control in other lease sale planning areas is estimated as: North Atlantic area—12 million acres; Mid-Atlantic area—10 million acres; Western Gulf of Mexico area—7 million acres; Northern and Central California—678 thousand acres, Southern California—7 million acres.

Figure 6-3.—Deferrals of Offshore Acreage for Military Uses


Central and Northern California
San Francisco
Santa Barbara
Los Angeles
Southern California
Boston
North Atlantic
New York
Atlantic
Norfolk
Charleston
South Atlantic
Savannah
Jacksonville
Mobile
New Orleans
Tampa
Central
Eastern
Western
Corpus Christi
Gulf of Mexico
■ DOD deferrals
▨ DOD density control ITL areas

NOTE: DOD areas not to scale.

SOURCE: U.S. Department of the Interior, Minerals Management Service.

considered conservative because some classified offshore uses have not been identified for security reasons. The OCS acreage deferred from oil and gas exploration and development, plus the OCS acreage which requires approval by the Department of Defense and therefore is constrained by operating stipulations (115 million acres), is about 30 percent greater than the total onshore area withdrawn for wilderness use on public lands in Alaska and the lower 48 States (88.6 million acres). Operating constraints include review and military approval of timing, placement, and location of rigs and platforms; provisions for suspension of operations at the request of the military; restrictions on electromagnetic radiation; and release of the military from liability for harm resulting to oil and gas operations from military operations.[29]

On July 25, 1983, the process of minimizing conflicts was addressed in a Memorandum of Agreement between the then Secretary of the Interior James Watt and Secretary of Defense Casper Weinberger. In the memorandum, the Department of Defense acknowledged that ''The OCS (Outer Continental Shelf) leasing program of the Department of Interior is an integral part of the nation's energy security program . . . and thus important to national defense.''[30] The two departments agreed to work together to assure that offshore development does not conflict with military training and other activities essential to the readiness of U.S. armed forces. Therefore, as a result of this Memorandum of Agreement, instead of relying entirely on leasing deferrals, the Department of Defense has expressed its willingness to promote compatible military and offshore oil and gas operations, whenever

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[29] Lease Sale 79, *Federal Register* (Dec. 6, 1983), p. 54796; Lease Sale 82, *Federal Register* (Aug. 27, 1984), p. 33987; Lease Sale 80, *Federal Register*, (Sept. 17, 1984), p. 36481.

[30] Memorandum of Agreement between the Department of Defense and the Department of the Interior on Mutual Concerns on the Outer Continental Shelf (July 21, 1983).

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possible, through the use of time-sharing agreements. The Navy and Air Force have, in some cases, offered to modify their activities to accommodate OCS exploration operations.

This policy, though workable, is not entirely satisfactory to industry. For example, to regulate the density of oil and gas operations in a portion of the Eastern Gulf of Mexico planning area, the Air Force adopted a policy that allows drilling operations within a 30-by-36 mile area. This system of density control over oil and gas operations has been termed the "postage stamp" approach. Eventually, the intent of MMS and the Air Force appears to be to periodically relocate the "postage stamp" so other areas in the Eastern Gulf of Mexico can be explored. There is also the possibility that more than one exploration area may be allowed at the same time. Several companies are now planning to drill in the first "postage stamp." However, outside of this "postage stamp," Shell Oil Co. was tentatively denied approval in November 1984 for an exploration permit to explore a previously leased block in the DeSoto Canyon of the Apalachicola Embayment of the Eastern Gulf of Mexico lease sale planning area off Eglin Air Force Base. This was the first time the Department of Defense had attempted to deny a qualified owner of an OCS lease access to that lease for exploration. As a result, the policies and procedures for regulating the density of oil and gas operations in military control areas are under review by the Department of Defense and MMS.

The Department of the Interior is currently considering the establishment of "military reservations" in offshore areas.[31] Authority for the withdrawal of OCS acreage from leasing is found in two statutes: 1) Section 12 of the OCS Lands Act (Public Law 82-212); and 2) Withdrawal of Lands for Defense Purposes Act (Public Law 85-337). The OCS Lands Act vests authority in the Secretary of Defense, with the approval of the President, to designate OCS areas off-limits for oil and gas development for "national defense" purposes. In addition, the Secretary of Defense may suspend operations on a previously existing lease with provisions for buyback from the lessee. The Withdrawal of Lands for Defense Purposes Act (Section 2) reserves the authority for withdrawing OCS areas from leasing for military purposes to Congress. Under the Act, applications for withdrawal must be acted upon by Congress before military reservations in the OCS are created. The two laws seem to be in conflict.

Whether the Executive Branch or Congress has authority to effect withdrawal of OCS lands for military purposes remains a question. The Withdrawal of Lands for Defense Purposes Act, having been approved in 1958, is the most recent expression of congressional intent. Legal interpretation often gives the latest statute preference over the one prior in time in the absence of an expressed repeal. If this interpretation is accepted to resolve the conflicts between the two laws, only Congress has the authority to establish offshore military reservations. This would probably require the introduction of legislation and appropriate hearings in conjunction with action by both Houses of Congress. On the other hand, another line of legal reasoning is that when Congress amended the OCS Lands Act in 1978, it did not change the law and thus implicitly reaffirmed the authority of the Secretary of Defense. MMS, in responding to the current concerns of the Department of Defense, has referred to military exclusions in OCS sales as "deferrals." This has avoided facing the issue of whether Congress or the executive branch has final authority to withdraw acreage from consideration for OCS oil and gas leasing. If the OCS Lands Act governs, the Secretary of Defense, with the approval of the President, can unilaterally withdraw OCS acreage for military use without the direct involvement of the Department of the Interior in the decision.

The withdrawal of OCS lands from oil and gas development for military reservations could, for practical purposes, remove a significant amount of potentially productive OCS acreage from future oil and gas development. In addition, operating restrictions on oil and gas activities in other portions of the OCS that may be considered suitable for shared uses could result in additional costs to the lessees and could delay the exploration-development sequence. Congressional concerns over conflicts between military use and oil and gas development may have contributed to the moratoria imposed in the appropriations process on OCS lease sales in the North Atlantic, Central and Northern California, Southern California, and the Eastern Gulf of Mexico during fiscal years 1982-85. If the current deferrals of OCS acreage now honored by MMS result in withdrawal of areas as "military reservations," the oil and gas industry could be permanently denied access to an even larger area than has been temporarily affected by the congressionally imposed moratoria (about 45 million acres in fiscal year 1985).

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[31] Testimony of William Bettenberg, Director, Minerals Management Service, before the House Committee on Interior and Related Agencies Appropriations (May 10, 1984), p. 605.

DISPUTED INTERNATIONAL BOUNDARIES

National jurisdiction over most of the known or potential resources on or under the U.S. Continental Shelf is largely uncontested. On March 10, 1983, when President Reagan established an EEZ for the United States, resource jurisdiction over the Continental Shelf within 200 miles of the U.S. coastline became even more firmly established. However, in some potentially important resource-producing areas in proximity to Canada, Mexico, Cuba, and the Soviet Union, international boundaries have been (or could be) contested. Settlement of these disputes may become of more concern as the United States—and these adjacent or opposite countries—improve capabilities to search for resources in more hostile environments and in deeper waters.

The primary responsibility for negotiating treaties to resolve these types of disputes lies with the U.S. Department of State. Typically, the Department of State consults with the Department of the Interior regarding subsea features and the resource potential of areas in dispute. Treaties must be ratified by Congress.

Areas of Potential Dispute

Gulf of Maine and Georges Bank

Jurisdiction over the Gulf of Maine and Georges Bank east of Cape Cod has been disputed between Canada and the United States. The region is a productive fishery and, although preliminary exploratory efforts on Georges Bank have been disappointing, it is considered to have potential for oil and gas. Maritime jurisdiction was disputed over an area between 13,000 and 18,000 square nautical miles in size. The dispute was submitted to the International Court of Justice (ICJ) for arbitration, pursuant to a boundary settlement treaty between the United States and Canada. The Court announced its decision on October 12, 1984.

Both the United States and Canada presented arguments to support their claims based on the ecology of the region, socioeconomic factors, and historic practices. The Court rejected these arguments, noting that "the respective scale of activities connected with fishing—or navigation, defense, or, for that matter petroleum exploration and exploitation—cannot be taken into account as a relevant circumstance or, if the term is preferred, as an equitable criterion to be applied in determining the delimitation line."[32] In determining an equitable line, the Court relied most heavily on geographical arguments. Thus, of primary importance was the notion that the delimitation should aim at an equal division of "areas where the maritime projections of the coasts of the States between which delimitation is to be effected converge and overlap." As a second criterion, the Court considered the length of coastline of each country in the Gulf of Maine. Accordingly, the middle of the three segments of the boundary line was adjusted in recognition of the greater length of the U.S. coastline in the region.

The Court gave Canada jurisdiction of the living and non-living resources of the northeast portion of Georges Bank (see figure 6-4). The United States had originally claimed the entire Bank while Canada had claimed about one-half of it. Thus, in this area, the line was established essentially midway between the claims of the two states. Canada, however, gained control over important fishing areas, most notably, scallop grounds.

As a result of this decision, Canada now may issue oil and gas leases on its portion of Georges Bank. The same, of course, is true for the United States in areas now under its jurisdiction. Thus,

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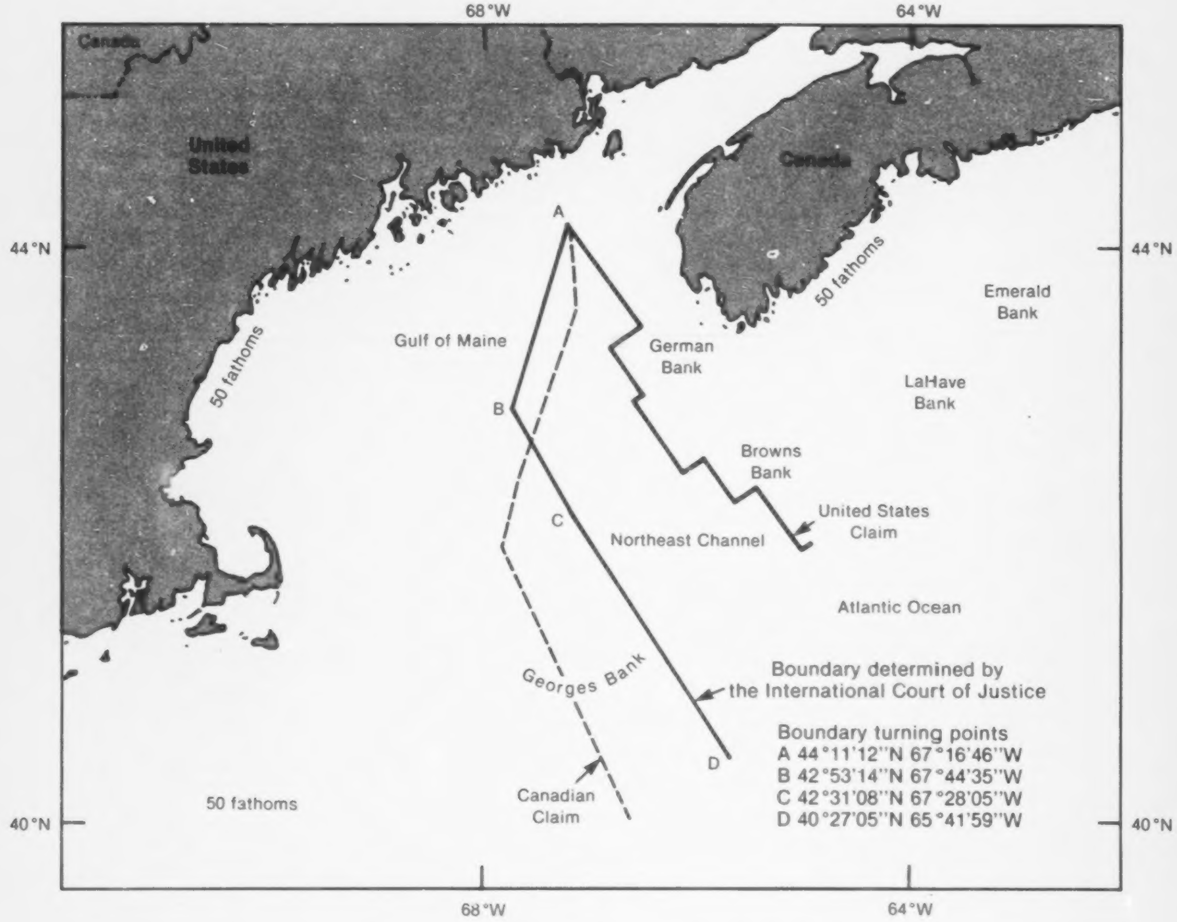
[32] International Court of Justice. *Case Concerning Delimitation of the Maritime Boundary in the Gulf of Maine Area: (Canada/United States of America)*, (Oct. 12, 1984), p. 102.

Figure 6-4.—U.S.-Canada Boundary in Georges Bank


68°W
64°W
Canada
United States
Canada
44°N
44°N
A
50 fathoms
Emerald Bank
Gulf of Maine
German Bank
50 fathoms
LaHave Bank
B
Browns Bank
C
United States Claim
Northeast Channel
Atlantic Ocean
Georges Bank
Boundary determined by the International Court of Justice
Boundary turning points
A 44°11'12"N 67°16'46"W
B 42°53'14"N 67°44'35"W
C 42°31'08"N 67°28'05"W
D 40°27'05"N 65°41'59"W
D
Canadian Claim
50 fathoms
40°N
40°N
68°W
64°W

oil and gas activities which occur on one side of the line could affect the other side. For instance, a gyre located over Georges Bank virtually assures that oil spilled on either side of the line will drift to the other side. Although U.S. and Canadian Coast Guards have developed a joint marine pollution contingency plan for the area, neither the United States nor Canada currently has a formal process in its OCS leasing operations for dealing with the environmental and socioeconomic concerns of the other country. Transboundary coordination and cooperation regarding OCS development activities adjacent to common boundaries could avoid many potential environmental problems.

Beaufort Sea

The offshore boundary between the United States and Canada in the Beaufort Sea also is in dispute. The area in question is small relative to the total continental shelf areas of both countries (6,180 square nautical miles), but favorable geologic conditions suggest it is potentially rich in hydrocarbon resources. Canada contends that the 141st meridian of longitude dividing Alaska and the Yukon delimits the offshore boundary. The United States claims that the boundary should be established using the equidistance principle, thus placing the boundary further east (see figure 6-5). The

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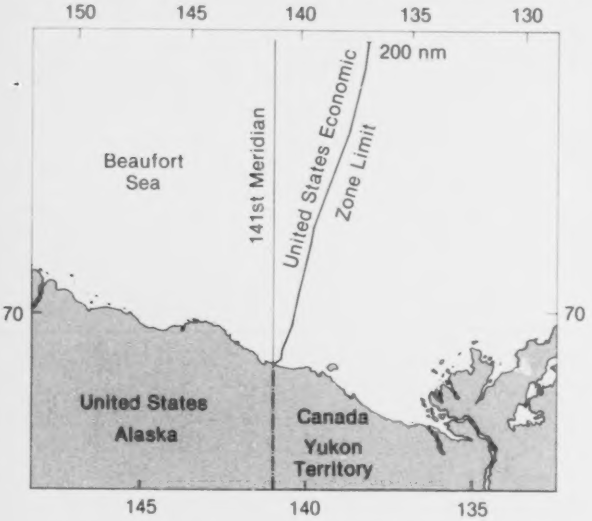
Figure 6-5.—U.S.-Canada Boundary in Beaufort Sea



legal basis for the Canadian claim is not altogether clear, but appears to rely on ambiguous language in the 1825 boundary agreement between the United Kingdom and Russia which specifies that the line of demarcation shall extend along the 141st degree of west longitude "in its prolongation as far as the Frozen Ocean."[33] Moreover, Canada has used the line as a national offshore fence for several purposes (e.g., oil and gas exploration permits have been issued up to the 141st meridian).

The United States does not agree that the United Kingdom-Russia Treaty of 1825 extended the land boundary into offshore areas, nor does the United States agree that any special circumstances exist that would justify such an extension. In the absence of "special circumstances," the 1958 Continental Shelf Convention calls for an equidistance line to be drawn. At this time, the crux of the matter appears to be what constitutes special circumstances, since the phrase is only vaguely defined in the 1958 Convention, and the 1982 United Nations Convention on the Law of the Sea does not provide any more detailed guidance.

The Beaufort Sea dispute has been quiet since 1975, and both countries have imposed an informal moratorium on offshore exploration and licensing in the disputed area. Although the Georges Bank ICJ decision supports the principle of equidistance modified by the amount of coastline held by each country—a finding which appears to favor the United States position in the Beaufort Sea—U.S. officials urge caution concerning the applicability of the Georges Bank decision to the Beaufort Sea. It is held by both countries that the circumstances of the Beaufort Sea dispute are unique and, therefore, the Georges Bank decision does not necessarily set a precedent for the resolution of the issue.

If an agreement locating the line cannot be reached, the United States and Canada may wish to consider other types of solutions to the problem. Joint exploration and development by Canada and the United States may be possible even though there are no specific provisions in the OCS Lands Act for joint activity. An executive agreement, which many scholars agree can overrule existing law, might be utilized to allow joint exploration and/or development to take place. In the absence of such an agreement, there still appears to be no legal reason why the United States, in concert with Canada, cannot hire a single firm or consortium to explore the area for both countries. Section 11 of the OCS Lands Act does not prohibit exploration without leasing. If exploitable resources are discovered, both countries might consider offering the disputed area for lease to one lessee while agreeing to decide at a later date how revenues are to be divided.

Bering Sea

The location of the line which separates Soviet and American resource jurisdiction in the Bering Sea also has been disputed. The line was established when Alaska was ceded to the United States by Russia in 1867. However, the Soviet Union and the United States have not been able to agree upon the method to be used in locating the line. The Soviets advocate use of the "rhumb line" method, a technique in use at the time the treaty was negotiated. The United States contends that the more modern "great circle" method of calculation best reflects the intentions of the negotiators of the 1867 Convention and should be used.[34] The rhumb line

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[33] David VanderZwaag and Cynthia Lamson, "Ocean Development and Management in the Arctic: Issues in American and Canadian Relations," unpublished paper for the United State-Canada Arctic Policy Forum (Banff, Alberta, Oct. 20-22, 1984).

[34] Harry R. Marshall, "International Boundaries and the 5-Year Outer Contilnental Shelf Oil and Gas Leasing Program." Paper presented at the meeting of the Outer Continental Shelf Policy Committee, New Orleans, Louisiana, (Oct. 26, 1984), p. 11.

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method places the line further east than the great circle method, and hence reduces the area assigned to the United States.

The 1867 line passes through the potentially oil-rich Navarin Basin; thus, there are important economic reasons for resolving the dispute. Upcoming sales in the Norton Basin and Chukchi Sea may also border on the 1867 line. The issue is even more important because the United States leased Navarin Basin tracts in 1984. Bids were received on 17 tracts within the disputed zone created by the two lines (see figure 6-6). However, these bids will not be finally accepted until the dispute is resolved. If it is later determined that it is not in the interest of the United States to accept these bids, deposits, which are being held in escrow, will be refunded with interest. However, if the dispute is resolved and the bids are accepted, bidders will be required to pay the remaining four-fifths bonus and the first year's rental and execute the lease.[35] Although four rounds of discussions concerning this sensitive issue have taken place since 1981, there is no indication as to when an agreement will be reached. Notwithstanding agreement on the location of the boundary, petroleum deposits may straddle the line. The methods used for apportioning common deposits in the North Sea between the United Kingdom and Norway may also be useful in the U.S.-Soviet boundary area.

If the United States and the Soviet Union cannot agree to a division of the area, several other options might be considered. A buffer zone could be created within which no oil and gas exploration will be allowed. An interim regime could be established that would permit exploration and provide the framework for future development and sharing of petroleum resources.[36] However, the possibility of joint U.S.-Soviet development of Navarin Basin resources in the foreseeable future is considered remote. Among other problems would be that of technology transfer, but that possibility, if successfully pursued, could have a positive effect on the two countries' relations.[37]

Continental Shelf

Delimitation of the outer boundary of the extensive U.S. Continental Shelf is another type of boundary issue. Given the vast amount of Continental Shelf acreage over which the U.S. may be entitled to assert resource jurisdiction, Continental Shelf delimitation is probably a more significant issue than delimitation of either opposite or adjacent state boundaries. In principle, the United States could assert resource jurisdiction under the "exploitability clause" of the 1958 Geneva Convention on the Continental Shelf, which defines the outer edge of the shelf as the point at which "the superjacent waters admit of the exploitation of the natural resources." The limits of exploitability are continuously being pushed into deeper and deeper water. However, precise rules have been promulgated in the 1982 Law of the Sea Treaty (Article 76) which, in some cases, would enable coastal States to extend Continental Shelf jurisdiction beyond the 200-mile EEZ. Even though the United States has not signed the Law of the Sea Treaty, it has stated that its only objections to the Treaty are the Part XI provisions pertaining to exploitation of the deep seabed beyond the limits of national jurisdiction.[38] The United States intends to abide by all other provisions, and, in particular, may use the Article 76 criteria for delimiting its Continental Shelf. Legislation introduced in the 98th Congress defined the Continental Shelf in terms consistent with Article 76.

The Law of the Sea Treaty is not yet in force. However, eventually it is expected to be operative for those countries that have signed and ratified it. Moreover, the Treaty will be a major factor in the development of state practice even for those countries that have not signed it. Many of its provisions may now be considered to be customary international law. Others will eventually be accepted as customary law, and thus generally become applicable even for non-signatories.

Gulf of Mexico

Delimitation of the Continental Shelf of the United States may involve conflicts with opposite or adjacent countries. One such instance may be

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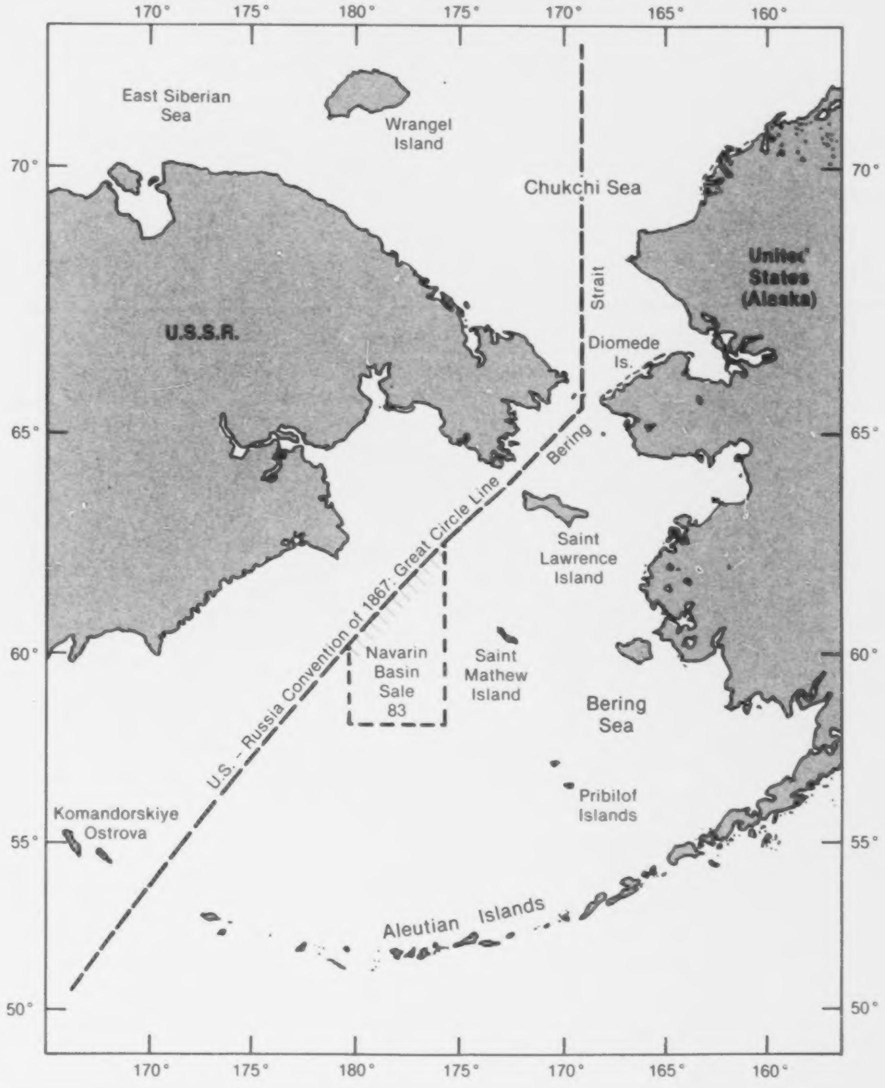
[35] "Final Notice of Sale: Navarin Basin." *Federal Register*, (Mar. 16, 1984), 49(53):10065.

[36] Robert B. Krueger, "Bering Sea Petroleum: A New Meeting Ground for the Soviet Union and the United States," unpublished paper (January, 1983).

[37] William E. Westermeyer, "Aspects of Arctic Energy Development," *Geopolitics of Energy* (March 1984), 6(1):7.

[38] Statement by the President, The White House, Office of the Press Secretary, (Mar. 10, 1983).

Figure 6-6.—U.S.-U.S.S.R. Boundary in Bering Sea


170°
175°
180°
175°
170°
165°
160°
70°
65°
60°
55°
50°
East Siberian Sea
Wrangel Island
Chukchi Sea
U.S.S.R.
United States (Alaska)
Strait
Diomede Is.
Bering
U.S. - Russia Convention of 1867: Great Circle Line
Saint Lawrence Island
Navarin Basin Sale 83
Saint Mathew Island
Bering Sea
Pribilof Islands
Komandorskiye Ostrova
Aleutian Islands

▭ Approximate area in Navarin Basin sale area between U.S. Great Circle Line (U.S. claim) and U.S.S.R. rhumb line (U.S.S.R. claim). Area is about 30 miles wide.

SOURCE: Minerals Management Service.

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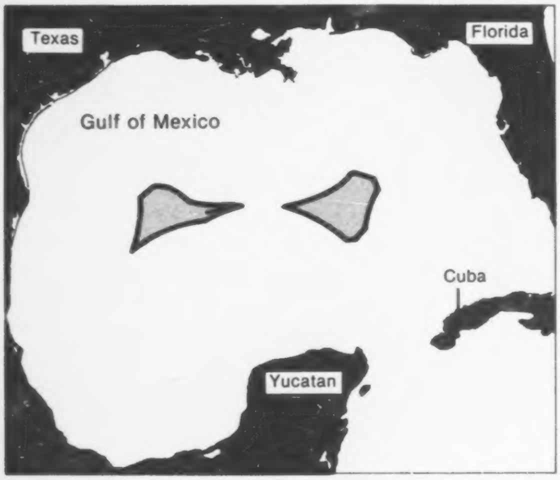
in the Gulf of Mexico. The United States, Mexico and Cuba border the Gulf, and their Continental Shelf claims could overlap in several areas (see figure 6-7). The United States has negotiated treaties with Mexico and Cuba delimiting boundaries in those areas where exclusive economic zones overlap. Neither treaty, however, has been ratified by the United States Senate. Some questions have been raised concerning Mexico's use of certain uninhabited islands off the coast of the Yucatan Peninsula as baseline points for the purpose of determining its EEZ boundary.[39] If these islands are not used to fix the Mexican EEZ boundary, the United States may be able to extend resource jurisdiction in some areas. However, the U.S. Department of State and many scholars regard the Mexican claim as legitimate.[40] Moreover, the United States uses islands as baseline points off its own coast.

Figure 6-7.—Gulf of Mexico Boundaries



Shaded areas — areas beyond the EEZs of bordering states.

Two areas exist in very deep water (10,000 to 12,000 feet) in the central Gulf of Mexico beyond the 200-mile exclusive economic zones of the bordering countries. The "western hole" is bordered by the EEZs of the United States and Mexico and the "eastern hole" is bordered by the EEZs of the United States, Mexico, and Cuba. Although there currently is little interest and no experience in exploiting resources in these deepwater areas beyond the EEZ, sediments do occur in both areas, and hence there is at least a possibility that hydrocarbons may be found.

The United States has not yet addressed the question of jurisdiction within the two holes. Interest in doing so at this time is low. Prospects for oil and gas development in these areas are considered to be remote, given the extreme depths and high costs of exploration and development. Nevertheless, all of the area within the holes can potentially be claimed by the littoral states according to the criteria of either Article 76 of the Law of the Sea Treaty or the 1958 Continental Shelf Convention.[41] Since several methods exist for determining the extent of the Continental Shelf, claims to these areas could overlap. Thus, bilateral or trilateral negotiations eventually may be needed to settle any disputes created by overlapping claims.

Dispute Settlement Mechanisms

Several mechanisms are available for resolution of boundary disputes. Third parties may or may not be involved in the process. A negotiated settlement without third-party intervention is usually preferable. Arbitration or mediation may also be considered. The Georges Bank dispute was settled by arbitration. This is a voluntary process, but the parties to an arbitration commit themselves to abide by the decision of the arbitrator. Mediation is also a type of arbitration, but the mediator of a dispute has no authority to impose a settlement. The mediator simply brings the parties together to help facilitate a solution to their problem. Numerous variations of these basic strategies are possible.

Determination of the proper location of the 1867 Convention Line in the Bering Sea will likely be made through bilateral negotiations between the United States and the Soviet Union. Four meetings already have taken place, the most recent of which occurred in July 1984. It is unlikely that either the United States or the Soviet Union would submit any dispute to a third party for arbitration or mediation if negotiations break down.

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[39] Senate Committee on Foreign Relations, "Three Treaties Establishing Maritime Boundaries Between the United States and Mexico, Venezuela, and Cuba," Executive Report No. 96-49 (Aug. 5, 1980), p. 7.

[40] Harry R. Marshall, "International Boundaries and the Five-Year Outer Continental Shelf Oil and Gas Leasing Program," paper presented at the meeting of the Outer Continental Shelf Policy Committee (New Orleans, Oct. 26, 1984), p. 14.

[41] Robert Smith, Office of the Geographer, U.S. Department of State, personal communication, (Oct. 30, 1984).

The United States and Canada will probably wish to give more thought to the advisability of using binding arbitration to settle the Beaufort Sea dispute if they perceive that, as in the Georges Bank dispute, the arbitrator will simply split the difference between claims without considering special circumstances. If bilateral negotiations are not successful in determining a mutually acceptable boundary line, mediation or some other conciliatory procedure may be needed. For example, the two countries could establish a joint U.S.-Canadian working group to devise an equitable solution and submit it to both governments for consideration.

The Law of the Sea Treaty also provides for the settlement of disputes through, for example, the International Tribunal for the Law of the Sea. When and if the Treaty comes into force, Mexico and Cuba could conceivably request that Continental Shelf delimitation in the Gulf of Mexico be determined by Treaty arbitration or conciliation procedures. Such mechanisms would be unavailable to the United States as a non-party. Presumably, if the issue becomes important to settle but cannot be settled through negotiation, an international tribunal not established by the Treaty, such as the ICJ, could be utilized.

LEASING POLICIES FOR OFFSHORE FRONTIER AREAS

Bidding Systems

The OCS Lands Act of 1953 authorized two bidding systems for use in offshore leasing: 1) cash bonus bid with a fixed royalty; and 2) royalty rate bid with a fixed cash bonus. The United States has traditionally allocated offshore tracts on the basis of the highest cash bonus bid with a fixed royalty payment based on the value of production. This bidding system is easy to administer, has appeared to promote efficient exploration and development of offshore tracts, and has been generally accepted by both government and industry.

However, in the 1978 OCS Lands Act Amendments, Congress required the Department of the Interior to test alternative bidding systems on not less than 20 percent and not more than 60 percent of the offshore acreage offered for lease each year for a 5-year period ending in September 1983. The five alternative bidding systems specified for testing were: 1) cash bonus bid with sliding scale royalty; 2) cash bonus bid with fixed net profit share; 3) cash bonus bid with fixed royalty and fixed net profit share; 4) profit share bid with fixed cash bonus; and 5) work commitment bid with fixed cash bonus and fixed royalty. Congress wanted to determine the effect of these bidding systems on competition for offshore leases, government revenues, and oil and gas exploration and development.

At the end of the testing period, the Department of the Interior still prefers the traditional bidding system for offshore leasing. After evaluating the alternative bidding systems in theory and/or in practice, the Department of the Interior concluded that their disadvantages outweighed their advantages in offshore leasing, as outlined in table 6-3. In testing the alternative bidding systems, it was found that they had little effect on the level of competition for OCS tracts, which is more directly related to an area's resource potential than to the method of leasing. No firm conclusions were reached regarding the development efficiency and revenue effects of alternative bidding systems, however, because most tracts leased under the alternative systems had not yet begun production.[42]

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[42] Minerals Management Service, "Report to Congress on Fiscal Year 1982 Outer Continental Shelf Lease Sales and Evaluation of Alternative Bidding Systems," (April 1983), p. 57.

Table 6-3.—Advantages and Disadvantages of Alternative Bidding Systems (authorized by OCS Lands Act Amendments of 1978)

Bidding system				
Bid variable	Fixed payment	Description	Advantages	Disadvantages
Cash bonus	Fixed royalty	Leases awarded on the basis of highest cash bonus payment plus percent of revenues, not less than 12½%. Usually 16⅔%.	Generally accepted bidding system in United States. Easy to administer.	Upfront cash bonuses may limit competition. Fixed royalties may overtax small fields and constrain development.
Cash bonus	Sliding scale royalty	Leases awarded on the basis of highest cash bonus plus percent of revenues, which increases with production.	May lower bonus bids and increase competition. Lease payments vary with field productivity.	Royalties may still be too high for small fields. May try to avoid higher royalty on productive tracts by slowing production.
Cash bonus	Fixed net profit share	Leases awarded on the basis of highest cash bonus plus percent of profits after capital recovery. Profit share not less than 30%.	May lower bonus bids and increase competition. Lease payments vary with field profitability.	Difficult to design and administer. May cause "gold-plating."
Cash bonus	Fixed royalty and fixed net profit share	Leases awarded on the basis of highest cash bonus plus percent of revenues and percent of profits.	May lower bonus bids and increase competition.	Regulations never written as too complex.
Royalty rate	Fixed cash bonus	Leases awarded on the basis of highest percent of revenues offered, plus fixed cash bonus.	Lower upfront payments may increase competition.	High royalty rate bids may constrain development.
Net profit share	Fixed cash bonus	Leases awarded on the basis of highest percent of profits offered, plus fixed cash bonus.	Lower upfront payments may increase competition.	High net profit share bids may constrain development.
Work commitment	Fixed cash bonus	Leases awarded on the basis of dollars to be spent on exploration, plus fixed cash bonus.	Provides for rapid exploration.	Government must forego high bonuses. Exploration program may be inefficient.

SOURCE: Office of Technology Assessment.

Both theory and experience indicate that the *royalty bidding system* and *the profit-share bidding system* may lead to the abandonment of small or marginal fields and prevent efficient development of resources. These systems tend to promote unrealistically high royalty rate bids or profit-share bids in competitive lease auctions. The high lease payments add to the costs of production and make development of some fields unprofitable. Royalty bidding in two offshore lease sales was found to lead to excessive royalty rate bids, which may discourage later investments.[43] Profit-share bidding was never tested.

The cash bonus bidding systems with either a *fixed net profit share* or *sliding scale royalties* have been more favorably evaluated in regard to development efficiency. Under both of these systems, lease payments vary with either field productivity or other factors. However, after it was tested in a total of 13 lease sales, the fixed net profit share system was not proposed for further use because of its complex accounting and administrative requirements.[44] While sliding scale royalty systems have proved easier to administer, they may discourage generally higher levels of production in order to avoid higher royalty rates. Despite this drawback, the Department of the Interior preferred the cash bonus bid with sliding scale royalty system to other alternative bidding systems.[45]

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[43] Department of the Interior, Office of OCS Program Coordination, "An Analysis of the Royalty Bidding Experiment in OCS Sale No. 36," (1975) and Bureau of Land Management, "Preliminary Analysis of Royalty Bidding vs Bonus Bidding at the Cook Inlet Sale," (Nov. 13, 1977).

[44] Resource Consulting Group, "Issues Associated with the Use of the Net Profit Share System for Leasing Outer Continental Shelf Oil and Gas Acreage," report to the Minerals Management Service (Sept. 27, 1982).

[45] Bureau of Land Management, "Bidding System Design for OCS Sale 71," (May 4, 1982).

Neither the *work commitment bidding system* or the combined *fixed royalty and profit share system* were tested in offshore lease sales. It is believed that work commitment bidding reduces government cash bonus revenues and may promote inefficient exploration efforts if not carefully designed.[46] Regulations were never written for the cash bonus bid with fixed royalty and fixed profit-share system, which is seen as administratively burdensome and complex.

The Department of the Interior has generally used the cash bonus bid with a lower royalty of 12½ percent (1/8) for leasing offshore tracts in frontier areas. This is the minimum royalty rate allowed by law and is used in recognition of the increased costs of developing oil and gas resources in hostile environments. The lower royalty rate is offered on blocks where analyses indicate that small discoveries may not be developed under the standard 16⅔ percent royalty. Starting in August 1981 through the end of 1984, the bonus bidding system with a 1/8 royalty has been used for leasing a total of 1,041 tracts in 19 lease sales. In general, the lower royalty rate has been offered on tracts in difficult ocean environments off Alaska and in deepwater areas of the other OCS planning regions.

The traditional cash bonus bid with fixed royalty bidding system has appeared to work well in conventional leasing areas such as the Gulf of Mexico in terms of assuring adequate competition for OCS tracts, fair returns to the government, and efficient exploration and development.[47] In frontier areas, the use of this system with a lower royalty rate has increased the economic incentive to explore in high-cost regions. In general, the cash bonus bid with fixed royalty bidding system has distinct advantages in its administrative simplicity, incentives for rapid exploration, and immediate returns to the government in the form of cash bonuses.

However, there may be disadvantages to allocating offshore frontier tracts by this bidding system. The requirement for upfront cash bonus payments may be a deterrent to comprehensive exploration of frontier areas. Alternative arrangements and even government incentives may be needed at some point to encourage continuing exploration in high-risk deepwater and Arctic regions. In addition, the low profit margins in frontier areas may cause fixed royalties (which are levied on gross income) to overtax small or marginal fields and lead to non-development of resources (see economic analysis in chapter 5). Even the lower 1/8 royalty rate may be too burdensome on some Arctic and deepwater fields.

Other countries, including the United Kingdom, Norway, and Canada, have generally used work commitment systems rather than cash bonus bidding for offshore leasing in frontier areas. This system is discussed in the appendix to this study. Under this system, firms agree to carry out a preplanned exploration program, drill a specified number of wells, or make a minimum expenditure in exploring a lease area. Firms which fail to carry out the terms of the work program can lose lease rights or any collateral paid to the government. In countries which use work commitment systems, lease tracts are far larger than those in the United States. In addition, the contract generally contains relinquishment provisions for returning portions of acreage to the government at a specified time. The work program, large size of the lease area, and turnback requirements jointly provide incentives for rapid exploration of vast offshore areas. Work programs also can be used to encourage firms to assess nonprospective offshore regions or to reassess relinquished acreage.

Other types of bidding systems which do not require initial cash payments for exploration rights may also provide more incentives to high-risk ventures in offshore frontier areas. Deferred bonus payments or cash bonuses payable only on commercial discoveries of oil would increase government/industry risk-sharing. These systems would retain the cash bonus bid variable and the financial competition which have been the basis of our leasing system.

Bidding systems with other types of downstream payments, such as sliding scale royalties, net profit shares, or even zero royalties, may be more effective in providing economic incentives for developing marginal oil and gas discoveries in offshore frontier areas. Under the sliding scale royalty system, the royalty rate increases with the production rate and government and industry shares of income are based partially on the productivity of the tract. Marginal resources and declining fields may be more likely to be produced because of the lower royalty rate attached to this production. At present, the primary disadvantage of the sliding scale royalty bidding system is that the royalty rate does not slide below the legal minimum of 12½ percent and won't greatly improve the profitability of small or marginal fields over the 12½ percent fixed royalty now in use. Sliding scale royalties that slide to zero percent may be needed to encourage the development of resources in frontier areas.

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[46] Resource Planning Associates, Inc. and Resource Consulting Group, Inc., "Alternative Procedures for Managing the Leasing of Nonprospective OCS Acreage," report to the Department of Energy (Jan. 29, 1981).

[47] W. J. Mead et. al., "Additional Studies of Competition and Performance in OCS Lease Sales, 1954-1975," report to the U.S. Geological Survey (1980).

Economic theory and empirical economic models, including the OTA computer simulation, indicate that net profit share payments also may be well-suited to offshore frontier areas.[48] Under this system, firms share the net income from tract development with the government at a specified profit share rate, fixed by law at no less than 30 percent. Of the several types of profit-sharing systems (e.g., investment account, rate-of-return, annuity-capital recovery), the United States has used the fixed-capital recovery system. Firms are allowed to recover their initial investment, plus a return on the investment, before sharing profits from oil and gas development with the government. Because this system takes into account the high costs, long lead-times, and other features characteristic of frontier areas, it provides for greater government risk-sharing. Small and marginal fields may not be as highly taxed and, therefore, are more likely to be developed.

Although work commitments, profit-sharing, and other leasing approaches have generally been accepted abroad, these bidding systems may be difficult to implement in the United States. Offshore leasing in the United States has always been based on competition between companies. Any leasing system used in the United States has to award lease rights on the basis of defined, objective criteria. In other countries, leasing conditions are often negotiated directly between private firms and the government.

In addition, effective design and administration of alternative bidding systems would require extensive testing and increased funding. The design of sliding scale royalty and profit-sharing systems is based on certain types of tract-specific information and calibration that is difficult for the government to achieve.[49] Post-production accounting in these systems often involves complex procedures for verifying costs, profits, and/or flow rates associated with individual leases. Work commitment bidding systems have administrative costs in negotiating terms and conditions and monitoring industry compliance. There has also been concern about potential government intervention into industry accounting and operational practices in the implementation of these bidding systems.

Because of the inconclusive results of the 5-year testing of the alternative bidding systems specifed in the OCS Lands Act Amendments, the General Accounting Office (GAO) has recommended that the requirement to test alternative bidding systems in offshore leasing be extended by Congress.[50] Further testing of alternative bidding systems, including some approaches not specified in the OCS Lands Act Amendments, is especially needed in offshore frontier areas. The effect of bidding systems on the level of competition is not particularly germane in the Arctic and deepwater, where competition will automatically be limited by the high-cost and high-risk nature of the tracts. But the effect of bidding systems on the rate of exploration and development in the frontiers is crucial in view of the need to assess and develop the resource potential of these areas.

The OCS Lands Act Amendments now gives the Secretary of the Interior great flexibility in designing bidding systems, which may consist of "any other system of bid variables, terms, and conditions....except that no such bidding system or modification shall have more than one bid variable."[51] As leasing and exploration proceed in offshore frontier areas, new approaches and modifications of lease conditions may be necessary to sustain the search for oil and gas resources. Other countries, such as the United Kingdom, have found it necessary to adjust lease payments and taxes in later stages of offshore activity to extend exploration and to encourage development of marginal resources. Through testing, the Department of the Interior could assess the advantages and disadvantages of alternative bidding systems in promoting exploration and development in frontier areas. It could also refine different bidding approaches and would be prepared to implement them on a more widespread basis if needed as an incentive to a second-round of leasing and development in the offshore frontiers.

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[48] R. J. Kalter, W. E. Tyner, and D. W. Hughes, "Alternative Energy Leasing Strategies and Schedules for the Outer Continental Shelf (Cornell University, Dept. of Agricultural Economics, December 1975).

[49] D. R. Siegel and J. L. Smith, "Does Profit-Sharing Leasing for Outer Continental Shelf Leases Need Finer Tuning?" *Oil and Gas Journal* (May 7, 1974), pp. 144-152.

[50] General Accounting Office, "Congress Should Extend Mandate to Experiment With Alternative Bidding Systems in Leasing Offshore Lands," (May 27, 1983).

Lease Terms

Other lease conditions may also need to be modified to encourage oil and gas activity in offshore frontier areas. For example, longer lease terms and larger tracts coupled with relinquishment provisions may be appropriate to frontier areas in conjunction with or apart from the implementation of new bidding systems.

As leasing in offshore frontier areas has increased, a greater number of OCS tracts have been offered and leased with 10-year rather than 5-year lease terms. The OCS Lands Act, as amended, provides for longer lease terms as an incentive to exploration and development in areas of unusually deepwater or difficult operating conditions. The longer lease terms have been offered for tracts in the Alaskan offshore, where weather and ice conditions may be severe, and for deepwater tracts in the Atlantic, Pacific, and Gulf of Mexico regions.

The first tracts with 10-year lease terms were offered in the 1979 joint Federal/State lease sale in the Beaufort Sea. This was the first Federal lease sale held in Arctic waters, and it resulted in the leasing of 24 Federal tracts which expire in 1990. Since that time, most of the lease sales held in the Alaskan planning areas have included tracts with 10-year leases. In 1984, the Navarin Basin sale (Lease Sale 83) and the Diapir Field sale (Lease Sale 87) featured some of the most remote tracts yet offered in U.S. waters and the most tracts leased with 10-year terms in single lease sales. About 70 percent of the tracts leased with longer lease terms have been in the Alaskan planning areas.

Ten-year lease terms also have been used for deepwater tracts in the lower 48 states, although the deepwater criteria have varied. The first truly deepwater OCS sales were held in 1981 in the Atlantic, where all tracts in water over 400 meters deep were offered with 10-year leases. However, a 900-meter criterion was used for Southern California Lease Sale 68 in June 1982, and 900 meters subsequently became the deepwater marker for tracts leased in the Pacific, Atlantic, and the Gulf of Mexico.

In December 1983, the Department of the Interior proposed increasing the acreage offered with 10-year lease terms by reestablishing 400 meters as the deepwater criterion and making 10-year lease terms automatic for all tracts in 400 meters of water or deeper.[52] The revision of the definition of deepwater from 900 meters to 400 meters is based on the increased amount of time needed to explore and develop energy resources in these water depths as compared to nearshore tracts. Lease terms are now decided on a sale-by-sale basis, but an automatic 10-year term tied to water depth could facilitate industry and government planning.

Critics of the longer lease terms believe they allow companies to delay exploration and development in offshore areas. At present, the 5-year lease term ensures that tracts are explored and developed in a timely manner, as leases are forfeited at the end of 5 years if they have not been drilled or declared prospective. Extensions of lease terms or "suspensions of operations" (SOPs) are available under special conditions. Critics of 10-year lease terms believe that the standard 5-year term and SOPs should be continued to be used in Alaskan and deepwater areas. However, SOPs are subject to changing policy interpretations or regulations and create greater uncertainty for the industry in frontier-area leasing.

Exploration diligence generally has been promoted by the requirement that lessees submit exploration plans and follow them. Holders of 5-year leases are required to submit exploration plans or statements of intentions to explore by the end of the fourth year of the lease term. However, holders of 10-year leases have not been required to submit these plans at a specified time, except as outlined in the lease offering. This often has been as late as the eighth or ninth year of the lease term. The Department of the Interior is now considering a requirement that exploration plans be filed within a set time on 10-year leases, although a milestone year has not been proposed. A requirement for earlier submission of exploration plans on 10-year leases could promote diligent exploration efforts while reducing the risks of the shorter lease term for the industry.

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[51] Section 8(a), Supra note 1.

[52] *Federal Register*, (Dec. 20, 1983), 48 (245): 56279-56281.

Tract Size

In addition to lengthening the lease terms, another proposal to improve the efficiency of exploration and development in offshore frontier areas is to increase the size of offshore lease tracts or blocks. The OCS Lands Act limits lease tracts to an area of nine square miles or 5,760 acres, unless it is determined that a larger area is necessary to comprise a reasonable economic unit. An option in frontier areas is to increase the average size of the tracts and to combine the larger tracts with relinquishment provisions.[53] This is standard practice in countries such as the United Kingdom, Norway, and Canada, where the average size of the tracts ranges from 90 square miles to 700 square miles.

Leasing larger tracts in offshore frontier areas can promote more rapid and efficient exploration strategies. Firms may be more willing to bid on large areas, which increase the probability that oil discovered by the lessee would be contained within its tract rather than on an adjoining lease. Firms would have less incentive to delay exploration in hopes that information from nearby drilling efforts reduces uncertainty about the value of a tract. In general, larger tracts increase the likelihood that owners will fully benefit from drilling information and thus may induce increased investment and exploratory activity.

In offshore frontier areas, increased tract size can provide for the surveying of vast amounts of acreage and the selection of prospective areas for drilling. The addition of relinquishment or turnback requirements could help assure the early identification of high quality acreage. Under this system, firms would relinquish a percentage of their acreage with exploration information at a specified time to the government, which could then lease the land again in smaller tract sizes. The United Kingdom, Norway, and Canada require that firms relinquish 50 to 65 percent of the lease tract after 3 to 5 years of exploration. The government benefits from the information generated by the broadscale exploration efforts.

Joint Bidding

The extremely high costs of exploration in frontier areas may prompt a need to allow joint bidding by the major oil companies on offshore leases. In October 1975, the Department of the Interior banned oil companies with worldwide production in excess of 1.6 million barrels per day of oil equivalent from participating in the same joint bidding group for offshore leases. This restriction became law with the enactment of the Energy Policy and Conservation Act of 1975. The OCS Lands Act Amendments modified the ban by allowing the Secretary of the Interior to authorize joint bidding by the majors on lands with extremely high exploration costs or where activity might not occur otherwise. The joint bidding ban so far has not been lifted for any sale.

Joint bidding has played a key role in OCS lease sales since the start of leasing in 1954. In the 35 pre-ban lease sales, about 10 percent of the bids were joint bids among the seven or eight largest oil companies. Recently, the majors not affected by the ban have frequently bid together on the more attractive and expensive tracts. The list of U.S. companies affected by the ban is updated every 6 months by the Department of the Interior and has included such firms as Exxon, Texaco, Mobil, Shell, Standard Oil of California, and Chevron.

A variety of concerns has prompted the continuance of the ban on joint bidding and even initiated politicial pressures in the early 1980s for extension of the ban to the 16 largest U.S. oil and gas companies. A major purpose of the ban is to facilitate the participation of smaller firms in offshore lease sales. Joint ventures among the majors might preclude their bidding with smaller firms, who would otherwise not gain entry to OCS activity. Joint bidding by the majors may also be a substitute for individual participation and reduce the number of competitors for OCS tracts and government cash bonus revenues. Greater competition and diversification of tract ownership are believed to provide for increased capital availability and more efficient exploration.

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[53] Resource Planning Associates, Inc. and Resource Consulting Group, Inc., Report to the Department of Energy, "Alternative Procedures for Managing the Leasing of Nonprospective OCS Acreage," report to the Department of Energy (Jan. 29, 1981), p. 3-16.

Joint bidding by the majors also prompts fears of collusion in other offshore areas and markets. At joint bidders' conferences, the majors may discern tracts on which other firms are not planning to bid, allowing them to lower their bids on these tracts. Joint ventures by the majors on OCS leases might also foster collusion in refining, processing, or related markets and increase their downstream market power.

A number of statistical analyses of OCS bidding and leasing data have tested the various hypotheses concerning the effects of the joint bidding ban. It is argued that the joint bidding ban itself is anticompetitive because the average number of bids per tract has actually decreased since the imposition of the ban.[54] Similarly, it has been shown that the size of the cash bonuses statistically increases as the concentration of joint bids increases and that the ban results in government revenue losses.[55] However, the percentage of offshore leases won by non-major oil companies and the number of successful bidders in offshore lease sales have increased since the ban was put in place.[56] All of these effects could be due to causes other than the joint bidding ban. In general, it is difficult to draw any strong conclusions based on these studies about the effect of the ban on OCS participation rates, bidding rates, or government revenues.

Removing the ban on joint bidding by the major oil companies would allow them to share the financial burdens and risks of investments in offshore frontier areas and might provide an additional incentive to exploration and development. The competitive effects of the joint bidding ban are less significant in Arctic and deepwater areas, where the number of firms which may participate is limited by the high costs of exploration. The joint bidding ban eventually may have unwanted negative effects in frontier areas in discouraging participation and in lowering bids.

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[54] Brian Sullivan and Paul Kobrin. "The Joint Bidding Ban: Pro- and Anti-Competitive Theories of Joint Bidding in OCS Lease Sales," *Journal of Economics and Business* (fall 1980), pp. 1-2.

[55] Alan Rockwood, "The Impact of Joint Ventures on the Market for OCS Oil and Gas Leases," *Journal of Industrial Economics* (June 1983), pp. 453-468.

[56] Leslie Grayson et. al., "Issues of Competition on the Outer Continental Shelf," *Journal of Natural Resources Law*, Spring 1983), p. 97.

Chapter 7

Environmental Considerations

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Chapter 7
Environmental Considerations

OVERVIEW

The development of petroleum resources in frontier areas of the Outer Continental Shelf (OCS) has become an important strategy in meeting the Nation's future energy needs. At the same time, a national consensus exists that protecting the environment from the effects of OCS development is equally important. Several laws are in force which address the potentially conflicting goals of environmental protection and resource development:

- *The Outer Continental Shelf Lands Act (OCS Lands Act) of 1953* (amended in 1978) mandates, among other things, that environmental studies be done "in order to establish information needed for assessment and management of environmental impacts on the human, marine, and coastal environments of the Outer Continental Shelf and the coastal areas which may be affected by oil and gas development."[1]
- *The National Environmental Policy Act (NEPA) of 1969* requires that all Federal agencies "utilize a systematic, interdisciplinary approach which will insure the integrated use of the natural and social sciences and the environmental design arts in planning and in decisionmaking which may have an impact upon man's environment."[2] The NEPA requires that an Environmental Impact Statement be prepared for major Federal actions.
- *The Marine Protection, Research and Sanctuaries Act* prohibits the unregulated dumping of waste materials into coastal and ocean waters and authorizes the Secretary of Commerce to designate offshore marine sanctuaries.[3]
- *The Endangered Species Act* requires that endangered and threatened species of fish, wildlife, and plants (and the ecosystems on which they depend) be determined and conserved, and it authorizes issuance of regulations necessary for protection of these species.[4]
- *The Marine Mammal Protection Act* provides for the conservation and management of marine mammals.[5]
- *The Coastal Zone Management Act (CZMA)* provides for management and protection of the coastal zone in cooperation with states.[6] Under the CZMA Federal actions must be consistent with approved state coastal zone management programs.
- *The Federal Water Pollution Control Act (FWPCA)* provides for the restoration and maintenance of the quality of the Nation's waters.[7] Among other things, the FWPCA requires discharge permits for OCS activities.

Several important environmental concerns are related to oil and gas development in frontier areas. If OCS exploration and development is to proceed with due regard for environmental protection and if sound lease management decisions are to be made, a large quantity of environmental information is needed. This is particularly true in Arctic frontier areas where relatively less is known about marine ecosystems and the manner in which they may be affected by OCS activities. Given funding constraints for environmental research, it is particularly important that such information be based on sound scientific procedures, provided in a timely manner, available to all interested parties, and relevant to the pre-and post-lease decisions that must be made. The major program for developing the information necessary for predicting, assessing, and managing the effects of OCS development is the Department of the Interior's Environmental Studies Program (ESP).

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[1] Public Law 83-212, 67 Stat. 462 (1953), 43 USC 1331-1356, as amended by Pub. Law 93-627, 88 Stat. 2126 (1975), and Pub. Law. 95-372, 92 Stat. 629 (1978). Section 20 (a)(1).

[2] Public Law 91-90, 83 Stat. 852 (1970), 42 USC 4321-4347, as amended by Pub. Law 94-52, 89 Stat. 258 (1975) and Pub. Law 94-83, 89 Stat. 424 (1975). Section 102 (2)(A).

[3] Public Law 92-532, 86 Stat. 1052 (1972), 33 USC 1401-1444; 16 USC 1431-1434, as amended by Public Laws 93-254 (1974), 93-472 (1974), 94-62 (1975), 94-326 (1976), and 95-153 (1977).

[4] Public Law 93-205, 87 Stat. 884 (1973), 16 USC 1531-1543, as amended by Public Laws 94-325 (1976), 94-359 (1976), 95-212 (1977), 95-632 (1978), and 96-159 (1979).

[5] Public Law 92-522, 86 Stat. 1027 (1972), 16 USC 1361-1407, as amended by Public Laws 93-205 (1973), 94-265 (1976), 95-136 (1977), and 95-316 (1978).

[6] Public Law 92-583, 86 Stat. 1280 (1972), as amended by Public Laws 93-612 (1975), 94-370 (1976), and 95-372 (1978).

[7] Public Law 845, 62 Stat. 1155 (1948), 33 USC 1251-1367, as amended.

It is beyond the scope of this assessment to do an exhaustive study of all biological resources that potentially may be affected by OCS oil and gas development. Some endangered species and some species of commercial importance which may be affected by oil and gas activities in Arctic areas are briefly considered. In lieu of a thorough analysis of all species, a detailed case study of bowhead whales is presented. Although not the only Arctic marine mammal listed as endangered, this species has received considerable attention in recent years. The possible vulnerability of bowhead whales to oil and gas activities has been the subject of intense debate among groups with different values and different objectives for Arctic development. Organizations including the Minerals Management Service (MMS), the National Marine Fisheries Service (NMFS), the Alaska Eskimo Whaling Commission, and the oil and gas industry have funded bowhead whale research in an effort to better understand the life history of the species and to determine the potential effects of OCS oil and gas activities on the species' behavior, survival, and reproduction.

Technology and techniques for oil spill containment and clean up in frontier areas are an important environmental consideration. While the oil and gas industry is genuinely concerned with preventing oil spills, the industry's capability to contain and clean up spilled oil in hostile environments has not been proven under actual conditions. This assessment focuses on the evaluation of the state-of-the-art of Arctic oil spill countermeasures. Less attention is given to deepwater spills. Although some deepwater oil spills may occur as the oil and gas industry moves further offshore, and although current capability to clean up such spills is limited, the equipment and methods for combating deepwater spills are essentially no different than those used for nearshore areas. Most deepwater spills will likely be of less concern than shallow water, nearshore spills because: 1) they generally occur in less biologically sensitive areas; 2) natural processes may often work to dissipate and degrade deepwater spills before significant damage can be done; and 3) greater distance from shore allows more lead time in which to consider what (if anything) is to be done.

ENVIRONMENTAL INFORMATION

Overview

The Department of the Interior (DOI) is responsible for leasing and managing OCS lands. As manager of the OCS leasing program, it is DOI's responsibility to ensure that environmental safeguards are employed. Specifically, DOI must ensure that OCS operations are

> . . . conducted in a safe manner by well-trained personnel using technology, precautions and techniques sufficient to prevent or minimize the liklihood of blowouts, loss of well control, fires, spillages, physical obstruction to other users of the waters or subsoil and seabed, or other occurrences which may cause damage to the environment or property, or endanger life or health.[8]

In order to meet this responsibility, DOI must be able to assess the environmental impacts of proposed offshore development, to delineate sensitive and unique areas, and to determine environmental hazards. The need for scientific information to accomplish these tasks led to the establishment of the Environmental Studies Program in 1973. This is the major scientific program designed to acquire information for OCS leasing.

ESP was initially administered by the Bureau of Land Management (BLM). However, in 1982, then Secretary of the Interior James Watt created MMS in order to streamline the administration of the leasing process, and the responsibility for the ESP was transferred to MMS. The environmental information generated by ESP research projects is used by the Secretary of the Interior and by the environmental assessment and leasing management divisions of the MMS in order to carry out their responsibilities under the NEPA and the OCS Lands Act. The Secretary of the Interior uses ESP information (as presented in NEPA documents and in the Secretarial Issue Document for each sale) for sale-related decisions.

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[8] Section 3(6), Supra note 1.

The studies program is divided among the four MMS regional offices—the Alaska, the Atlantic, the Gulf of Mexico, and the Pacific regions—and the headquarters office. Alaska studies have received the most attention because the Alaska OCS is the largest OCS area (comprising about 74 percent of OCS lands) as well as the least explored and least studied area.

Relatively little information was available prior to 1973 to assess the potential impacts of oil and gas development, and data gaps were especially large for the Alaskan OCS. Moreover, BLM—primarily a western land management agency—initially did not have the inhouse capability to extend its environmental studies program to the Alaskan OCS. Therefore, in 1974, BLM contracted with the National Oceanic and Atmospheric Administration (NOAA) to design and manage an environmental studies program for the Alaskan region. NOAA initiated the Outer Continental Shelf Environmental Assessment Program (OCSEAP) for Alaskan studies. OCSEAP has become one of the most comprehensive programs for the collection and evaluation of Arctic environmental information. It is also the largest single segment of the environmental studies programs funded by the MMS.

MMS directly manages all environmental studies in the Atlantic, Gulf, and Pacific OCS regions and some of the Alaskan OCS studies (including some transport studies and endangered species and monitoring studies). MMS also manages the Alaska Social and Economic Studies Program. This program, begun in 1976, funds studies which investigate the impact of offshore oil and gas development on economic, social, and cultural systems of coastal residents, communities, and regions. Seventy-five percent of MMS funds for social and economic studies have been spent in Alaska.

The assessment of environmental information needs and the development of environmental studies occur annually through the MMS Regional Studies Plans. Assistance in developing Regional Studies Plans is given by Regional Technical Working Groups in each OCS area. In the Alaska region, this group is composed of representatives from the MMS, the State of Alaska, the Fish and Wildlife Service, the NMFS, the U.S. Coast Guard, the Environmental Protection Agency, industry, and private groups. The OCS Advisory Board Scientific Committee also comments on the plans during development.

Studies are ranked according to: 1) the importance of the research to decision-makers; 2) the date of the decision for which the study results are to be used; 3) the generic applicability of results or techniques from the study; 4) the availability and completeness of existing information; and 5) the applicability of the information to issues of regional or programmatic concern.[9]

With respect to the Alaskan OCS, information needs identified by MMS are utilized by NOAA to prepare an annual Technical Development Plan for OCSEAP research.[10] OCSEAP research is performed at universities, State and Federal agencies, private firms, and research institutions. Private firms currently receive the greatest proportion of ESP funding in Alaska, and that proportion has been increasing.

The results of research projects are utilized in the OCS leasing decision process at various stages. The steps in which scientific information is incorporated into leasing decisions are described in table 7-1. Results from the studies program and other scientific information are also utilized in post-lease permitting, post-lease environmental analyses, and (if necessary) development environmental impact statements.

Expenditures

MMS spent approximately $370 million on the ESP between 1973, the year in which the program was initiated, and 1984, the latest year for which data are available (see figure 7-1). About half of

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[9] Minerals Management Service, Alaska Outer Continental Shelf Region, *FY1985 Alaska Regional Studies Plan: Final* (October 1983).

[10] National Oceanic and Atmospheric Administration, *Outer Continental Shelf Environmental Assessment Program: FY 84 Technical Development Plan* (August 1983).

Table 7-1.—Use of Environmental Information in Leasing Process

Area Identification

MMS analyzes recommendations based on environmental information from FWS, DOI, the public, and affected States.

MMS Scoping Meeting

Issues concerning proposed lease areas identified. Attended by MMS, other Federal and State agencies, oil and gas industry, environmental groups, and citizen representatives.

MMS/OCSEAP Synthesis Meeting

Primary management tool for incorporation of scientific results into OCS leasing process. Scientists and science managers discuss research results, identify data gaps, determine how results answered OCS management questions. Full synthesis meeting now held only for first generation lease sales. Smaller meetings held for second or third sales in an area,

Synthesis Report

Synthesis Report prepared by NOAA (for Alaska OCS regions) used by MMS in preparation of Draft Environmental Impact Statement (DEIS).

Draft Environmental Impact Statement

MMS prepares the Draft Environmental Impact Statement based upon available research results from a variety of sources, including, when applicable, the OCSEAP Synthesis Report (or results from the Synthesis Meeting if report not yet available). DEIS must address major issues related to the proposed action.

Endangered Species Consultation

MMS required to consult with NMFS for formal biological opinion.

Final Environmental Impact Statement

Required to address proposed alternatives discussed in DEIS; incorporates public comment received on DEIS.

Secretarial Issue Document

Addresses economic, industry, social, and environmental concerns. Used by Secretary of Interior in lease tract sale decision.

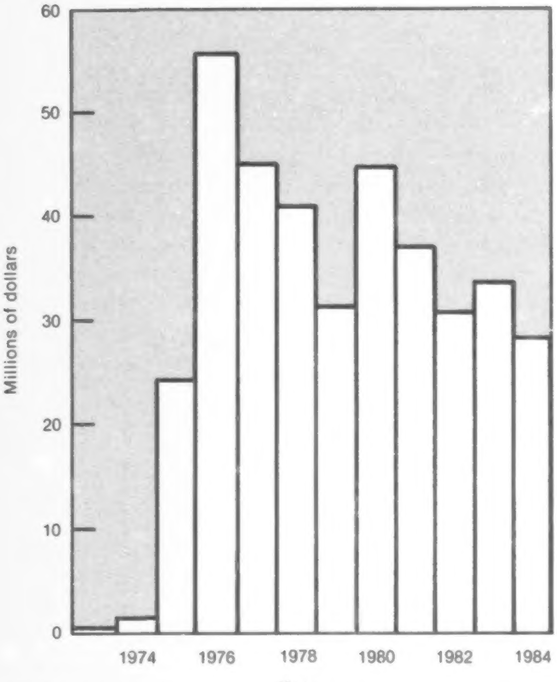
Final Notice of Sale

Decision to lease, approved by Secretary of Interior. Any changes in bidding systems, lease stipulations, lease blocks incorporated here.

SOURCE: Office of Technology Assessment.

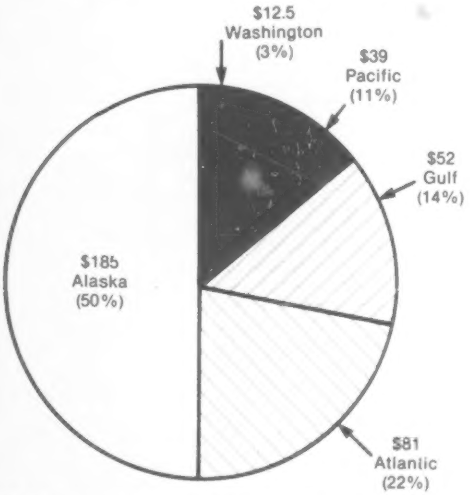
these funds have been expended in the Alaska OCS region (see figures 7-2). The other half of the budget has funded studies in the Atlantic, Gulf, and Pacific regions and in the Washington headquarters office. Program expenditures increased dramatically in 1975 and doubled again in 1976, in response to the decision to lease offshore areas for oil and gas exploration in Alaska.

Figure 7-1.—Expenditures for Environmental Studies (1973-84)



SOURCE: Minerals Management Service, Branch of Environmental Studies.

Figure 7-2.—Expenditures for Environmental Studies by Region (1973-84) (millions of dollars)



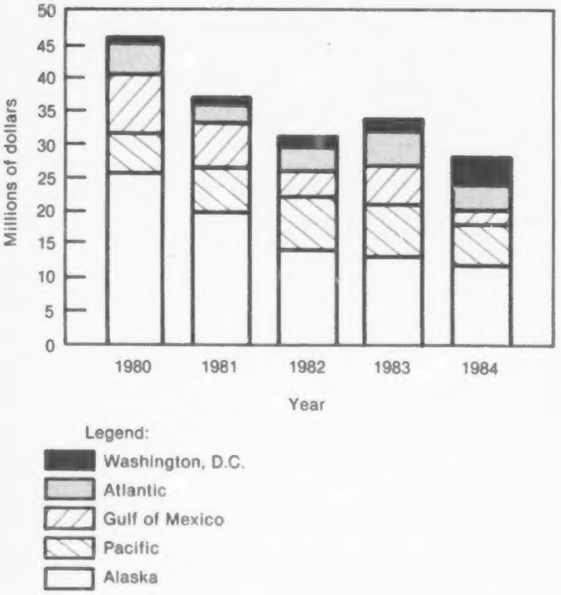
SOURCE: Minerals Management Service, Branch of Environmental Studies.

However, since 1980, when expenditures for environmental studies totaled more than $45 million, budgets for the program have declined, and, in 1984, yearly funding dropped below $30 million (without accounting for inflation) for the first time since 1975. This trend is consistent with reduced non-defense spending throughout government under the 1981 through 1984 budgets.

Since 1980, ESP funds for the Alaska region have decreased more rapidly than funding for studies in other areas (see figure 7-3). Although the Alaska region budget is still the largest, it has decreased from 55 percent of the budget in 1980 to 45 percent in 1984. Funds for Alaska OCS studies have been reduced some 49 percent since 1980, from $25.3 million to $12.9 million in 1984 (see figure 7-4). Funding for Gulf of Mexico studies has also decreased, from 19 percent of the budget in 1980 to less than 14 percent in 1984. The proportion of the total budget spent for Atlantic and Pacific region studies has increased since 1980, although total dollar amounts have declined. Funding for the Washington, D.C. headquarters office also increased in this period, and in 1984 accounted for 5.3 percent of the total ESP budget.

Over the 11-year period from 1973 through 1983 about 86 percent ($148 million) of Alaska environmental studies funds have been used for NOAA/OCSEAP studies. The relationship between NOAA and MMS has changed in recent years. MMS has gradually upgraded its technical capabilities which it lacked in the early years of the program, and has assumed more responsibility for managing Alaskan environmental research. The budget for MMS (non-OCSEAP) Alaskan studies has increased—but not dramatically—since 1980, but funding for OCSEAP studies has decreased more than 50 percent, from just over $21 million in 1980 to less than $8 million in 1984. Thus, the *relative* importance of MMS inhouse and directly contracted environmental studies has increased significantly.

Figure 7-3.—Recent Trends in Environmental Studies Funding (1980-84)



SOURCE: Minerals Management Service, Branch of Environmental Studies.

Types of Studies

ESP and OCSEAP studies may be classified into seven categories. These are:

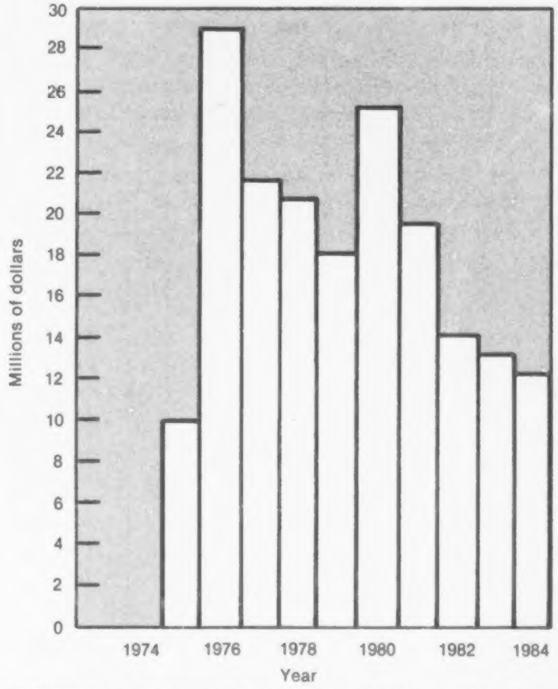
Contaminant Distribution Baseline Studies

These studies were designed to learn more about the background levels of hydrocarbons and heavy metals in the Alaskan OCS in order to establish a baseline for predicting changes if these kinds of contaminants were released during oil and gas development. Funding for baseline studies in the Alaska region was greatest in 1976, 1977, and 1978 (see figure 7-5).

Biological Studies

Biological studies have investigated the distribution and population dynamics of birds, mammals, fish, littoral biota, benthic biota, and plankton. These studies have received the largest total amount of funding since the inception of the program.

Figure 7-4.—Funding for Alaskan Environmental Studies



SOURCE: Minerals Management Service, Branch of Environmental Studies.

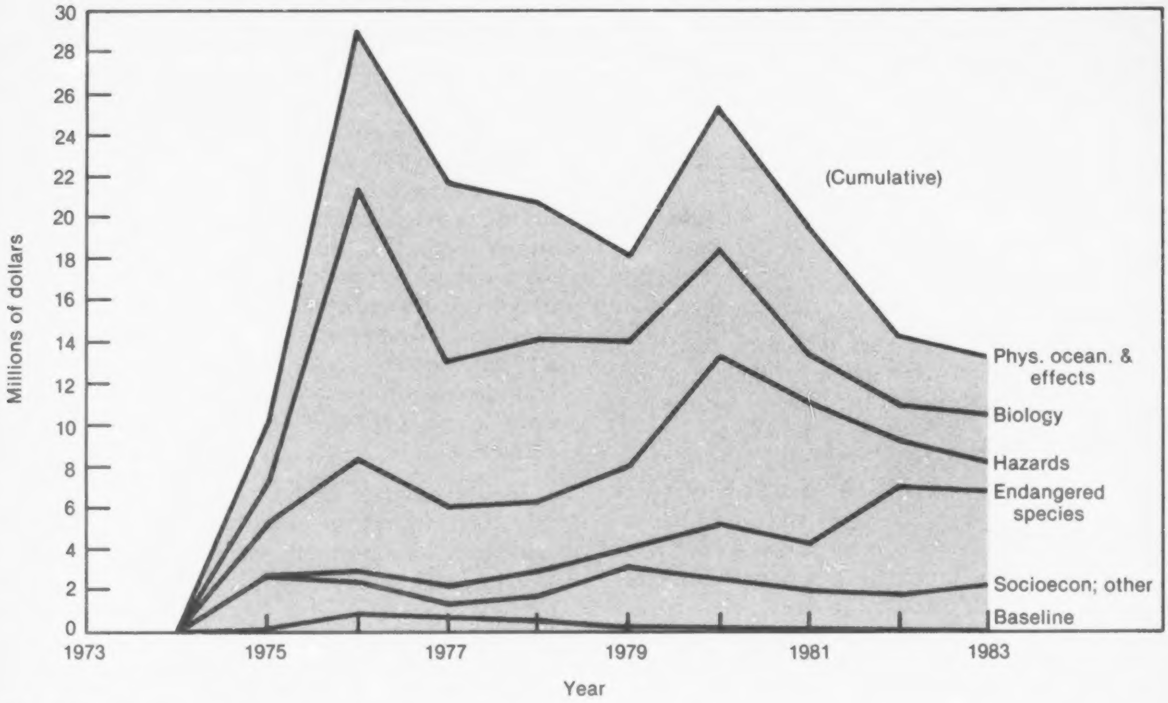
Hazards Studies

Environmental hazards studies encompassed investigation of seismicity and volcanicity; determination of the character of bottom sediments and subsea permafrost; quantification of the nature, intensity, and frequency of sea ice hazards; and determination of wave heights. The objective of these studies has been to acquire information useful for determining hazards to drill ships, platforms, and pipelines, and for determining the probability of accidents caused by environmental hazards.

Transport Mechanisms

The objective of transport studies has been to determine the mechanisms involved in transport, weathering, and dispersion of spilled oil, oiled sediments, and other contaminants. A major part of this program has involved physical oceanography studies, including development of a sophisti-

Figure 7-5.—Funding for Alaskan Environmental Studies by Type (1973-83)



SOURCE: Minerals Management Service, Branch of Environmental Studies.

cated oceanic circulation model, a simplified version of which the MMS now uses for risk analysis. Such models are important because they help to focus impact assessment on identified vulnerable coastlines and marine biological resources at risk. They also can lead to local site-specific models which could allow assessment of OCS activities affecting circulation patterns, or whose impact is distributed regionally by circulation (e.g., causeway construction, sand and gravel extraction, hydrocarbon production byproducts, and marine construction siting).

Effects Studies

Effects studies investigate the interactions of spilled oil and other contaminants on individual species and ecosystems. For example, effects studies have been done for salmon, herring, and king and tanner crabs.

Ecosystem Processes

The purpose of process studies is to investigate and understand aspects of community structure and function. Although some biological process studies have been undertaken in specific ecosystems, there are still other ecosystems for which processes need to be better understood. Studies of ecosystem structure and processes tend to involve many scientists in different disciplines, all collecting field data concurrently. Thus, these studies are expensive and site specific. Ecosystem studies have been conducted at Simpson Lagoon and Pearl Bay, and studies of the Yukon Delta and the North Aleutian Shelf are in progress.

Socioeconomic Studies

The objective of these studies is to assess the social costs of OCS operations, e.g., the impacts of coastal development, tanker traffic, and marine pollution associated with OCS development; effects on local cultural systems; damages to personal property and property values; and costs to recreational and/or subsistence uses.

Trends in the Environmental Studies Program

Scope and Direction

Baseline studies. Baseline characteristics and contaminants in Arctic regions have been extensively studied. However, this class of background study was criticized by scientists in the 1978 National Research Council ESP review because the natural geographic and temporal variability of the marine environment is so great, both in space and time, that useful baselines could not be established without prior information on the types and specific locations of the development to be undertaken. Thus, the studies would be of little use either for predicting changes or for quantifying change during and after development. Consequently, funding for these studies was cut significantly in 1979, and, beginning in 1982, no funds were allocated for baseline studies. Now that development in specific Arctic OCS areas may occur, concern about monitoring the effects of OCS activities has increased, and more site-specific work will be necessary.

Biological studies. Funding for biological studies has decreased in the last several years by a greater proportion than decreases for the ESP as a whole. Basic information about Arctic biota is now relatively well known. However, data are still lacking for many geographic and subject areas (e.g., areas outside the fast ice zone in the Beaufort Sea). The Interagency Committee on Ocean Pollution Research, Development, and Monitoring considers the Beaufort Sea living resources studies important because they are process oriented.[11] These studies have proven more effective than studies which simply enumerate and catalog biota. For example, the results of ecological process studies in Simpson Lagoon provided the nucleus for biological stipulations attached to the joint State/Federal Beaufort Sea lease sale in 1979 and for other lease sales.

Funding for endangered species studies has increased significantly since the beginning of the ESP. In fiscal years 1982 and 1983, endangered species studies accounted for the largest percentage (about 35 percent) of Alaska ESP expenditures. The endangered species most studied have been bowhead and gray whales. The Endangered Species Act is a major reason that studies of endangered whales have been emphasized. Federal agencies must ensure that actions which they authorize, fund, or carry out are not likely to jeopardize the existence of any endangered or threatened species. The emphasis on bowhead whale studies, in particular, is also motivated by regional political concerns. Several interest groups have important, but not necessarily compatible, interests concerning the species.

Hazards studies. In the early stages of the ESP, there was a large geological hazards assessment program. Funding for environmental hazards studies peaked in 1980 at $12.6 million per year (of which two-thirds was allocated to Alaska OCS studies). Since then, funding has been reduced significantly. In 1983, total ESP funding amounted to only $1.4 million. The decrease in funding has corresponded to an evolution in DOI policy concerning the appropriate scope of the Federal Government's research responsibilities relative to those expected of the private sector. It is the MMS position that most hazards studies should be undertaken by industry. In particular, industry must undertake site-specific hazards studies in order to properly design offshore structures, pipelines, etc., and must provide the data to the MMS Offshore Field Operations for exploration plan and permit approvals.

Reduced ESP funding for geological hazards studies has been controversial. Some groups believe that the government should have an independently acquired, public body of information in order to properly perform its oversight role of assessing the performance of the industry in their proposed future OCS activities, and that the current program does not provide the government with this capability. Thus, it is contended that government needs a stronger capability to evaluate offshore hazards and the measures that industry is developing to respond to them. This would require more Federal involvement in hazards studies and more funding.

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[11] Interagency Committee on Ocean Pollution Research, Development, and Monitoring, *Marine Oil Pollution: Federal Program Review* (April 1981).

Transport mechanism studies. Transport studies generally have been of high quality, especially in Alaska where relatively less was known. Nevertheless, regional gaps remain, such as the need for better information about sediment transport in the Bering Sea (e.g., for designing gathering pipelines and subsea completions) and the need for weather and ice data in the Bering and Chukchi Seas. Most transport studies require data acquisition over periods of years, requiring many instruments and repetitive surveys. However, risk analysis is conducted using simulation models which project probable transport based on physical and chemical properties and available field data.

Effects studies. Although research needs remain, funding for effects studies has decreased by more than 50 percent since 1980. Knowledge of effects of offshore development (e.g., the effects of oil spills, the effects of artificial structures on living organisms, the effects of coastal modifications on the natural movement of fishes, and the effects of noise) is currently deemed by some to be inadequate. Others take the view that such effects (with the possible exception of noise) would be too localized to play a major part in formulating large-scale research policy. Several effects studies have been completed or are underway.

Socioeconomic studies. In comparison to other studies areas, relatively little money has been spent by MMS on socioeconomic studies (e.g., $2.0 million in 1983). Social and economic studies are often less expensive than equipment-intensive environmental studies. Hence, although less money has been spent, the number of socioeconomic studies funded through 1983 (133) is large relative to the numbers of studies funded in other categories. Most of these funds have been spent in Alaska. On the other hand, the 1981 report of the Interagency Committee on Ocean Pollution Research, Development, and Monitoring notes that higher priority is generally assigned to studies which are legally mandated or which are designed to avoid lawsuits or to accommodate political concerns. Thus, studies addressing economic and social issues may have greater difficulty meeting the criteria for funding.

Management

Funds allocated to the OCSEAP program have decreased since 1980, and MMS has increased its capability to manage environmental studies. The relationship between OCSEAP and MMS is changing, and some critics have argued that the larger role for MMS in directly managing Alaskan environmental studies may not be the optimum situation. The argument against MMS's involvement is that the agency responsible for OCS leasing should not also be in charge of determining what environmental research is necessary and of supervising subsequent research efforts. Thus, a continuing OCSEAP role is seen by some as desirable in order to help ensure that scientific knowledge is produced which is needed to achieve a balance between offshore oil and gas development and environmental protection, thus safeguarding the public interest. Conversely, the OCSEAP program has always been supported by interagency transfer of BLM/MMS funds, and OCSEAP managers have worked under the guidance of the MMS. MMS is legally required by the OCS Lands Act and NEPA to acquire information relevant to potential environmental impacts, and is increasing its capability to do this itself.

In 1978, a National Research Council review of the ESP concluded that the program at that time did not effectively contribute to leasing decisions or to the accrual of sound scientific information adequate for OCS management. The National Research Council cited several reasons for poor program design, including low priority within DOI and the paucity of professional experience within the staff.[12] Many of the important issues raised by the NRC have been addressed, and, in particular, the creation of MMS, improvements in staff, and redesign of the program have produced information more directly related to the management of OCS activity. However, despite the fact that MMS is now conducting the post-lease monitoring required by the OCS Lands Act, MMS's research efforts—given its leasing mission—have mostly been focused on immediate rather than long-range information needs. Approaches should be considered that help ensure that important longer term studies, not motivated by near-term leasing decisions, are undertaken.

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[12] National Research Council, *OCS Oil and Gas: An Assessment of the Department of the Interior Environmental Studies Program* (Washington, DC: National Academy of Science, 1978).

Funding

Each year less money is available for environmental studies, and fewer such studies are funded. This raises the fundamental question of what level of funding is adequate for OCS decision making and management, and, related to this, what information base is adequate for decision making. On the one hand, a large body of OCS environmental information has been acquired in the past 10 years. The current information base is increasingly sufficient for most pre-lease decisions in all OCS regions. This is a major reason why MMS is now shifting the focus of environmental studies toward research designed to answer operational questions.

Nevertheless, the stated national objective is to increase reliance upon domestic petroleum resources, and at the same time minimize environmental disturbance. To do this properly, a significant research effort is still required—particularly for post-lease studies and in Arctic and deepwater areas—and research in OCS frontier areas is expensive. Adding to the expense of Arctic and deepwater studies is the fact that opportunities for conducting research are constrained by weather and other variables.

The Federal budget is under scrutiny, and it may be difficult to increase funding for OCS environmental studies. However, the size of the Alaskan OCS and the amount of estimated oil and gas reserves, the frontier character of the Alaska region, and the high costs of logistics and support operations may warrant the continued emphasis on funding for this area relative to the other OCS areas. It is not necessary, however, to rely entirely on research funded by the ESP/OCSEAP program to answer all important research questions. Some results from other research programs, both Arctic and non-Arctic (e.g., the National Science Foundation's Arctic Research Program, MMS's Technology Assessment and Research Program, etc.) may be useful.

Emphasis

The main thrust of the ESP, until recently, has been to gather information useful primarily for the leasing decision itself. In 1978, the National Research Council criticized BLM's (now MMS) inadequate program design for post-lease environmental studies. Increasing emphasis is now being placed on post-lease management and monitoring studies. For instance, in 1984, MMS implemented a long-term monitoring program for the Beaufort Sea to determine if any trends can be observed in concentrations of heavy metals and other contaminants. Such studies are expensive and require continuous funding.

Both the MMS and NOAA are chartered to do ocean monitoring studies. MMS is specifically charged with monitoring the effects of OCS operations while NOAA has a more general mandate to study long-range effects of pollution and man-induced changes of ocean ecosystems. This overlap of responsibilities is sometimes confusing and has fostered occasional competition between MMS and NOAA. In this regard, the Biological Task Forces that have been organized for the Bering and Beaufort Seas may be able to play a larger role in fostering coordination and cooperation among the Federal environmental monitoring programs. These task forces are composed of agency representatives from MMS, the Environmental Protection Agency (EPA), Fish and Wildlife Service, and NMFS (State and local observers participate as well in Alaska). They were created to give these agencies an opportunity to advise MMS's Regional Supervisor of Field Operations on the biological aspects of the lessee's proposed activities and to recommend appropriate actions for protecting biological resources.

Public Participation

Environmental groups are concerned that public input to the decisionmaking process has decreased since 1981. Environmentalists perceive that less scientific information related to the oil and gas leasing program is being disseminated, and that the public is therefore less informed than it was immediately after the OCS Lands Act Amendments were implemented in 1978. For example, environmentalists contend that Synthesis Reports, which are helpful to the public in evaluating environmental impact statements, are not available sufficiently in advance of lease sales. DOI is attempting to respond to the criticisms of the environmental groups with regard to dissemination of study results. Beginning in July, 1984, for instance, DOI began publishing a list of offshore scientific and technical publications available to the public. A list of OCSEAP-supported publications has been available since 1980. In addition, the ESP has begun a project to make available abstracts of most prior environmental studies, and MMS now conducts annual Information Transfer meetings to help disseminate the results of studies. Nevertheless, funding for publication of research results has declined, and it does take longer to get information published.

Public participation and input to the process of determining research needs has also decreased, according to environmental groups monitoring DOI's OCS program, and it has thus become more difficult for the public to participate in framing the research questions to be addressed by the environmental studies program. The MMS argues that there are ample opportunities for public participation, including Scoping Meetings, which are held at an early stage in the lease process to give citizens a chance to express their concerns. However, another useful forum for involving the public at an early stage of the research planning process, the OCSEAP Users Panel, no longer exists, and the Regional Technical Working Group in Alaska has been meeting less frequently.

BIOLOGICAL RESOURCES

Overview

Since the Torrey Canyon and Santa Barbara oil spills in 1967 and 1969, the effects of oil spill accidents have been studied intensively.[13] Despite this study, there is still a great deal of controversy regarding the effects of oil in the marine environment. A major problem in assessing the effects of pollution is that natural variation of biological populations and water quality in the ocean is very great and poorly understood. It is difficult to detect changes and to relate these changes to a specific pollution event. MMS has made some attempt to rank the OCS planning areas in terms of their potential vulnerability to spilled oil (see box).

There have been few documented effects of oil in the water column, even from such massive spills as Amoco Cadiz and Ixtoc I. On the other hand, oil regularly reaches bottom sediments after a spill, and may persist in these sediments for years. When fresh oil reaches the bottom, effects including death among sensitive benthic species may occur. Sublethal contamination of zooplankton and benthic invertebrates is common. Studies have shown (e.g., of the Arrow spill off the coast of Nova Scotia) that

Relative Environmental Sensitivity of the OCS Planning Areas[a]

Planning area	Overall total score
St. Matthew-Hall	345
Norton Basin	307
Kodiak	303
Shumagin	295
Gulf of Alaska	283
St. George Basin	278
Aleutian Arc	278
North Aleutian Basin	264
Cook Inlet	255
Central Gulf of Mexico	253
North Atlantic	245
Central California	244
Northern California	234
Hope Basin	231
Southern California	222
Chukchi Sea	212
South Atlantic	206
Eastern Gulf of Mexico	204
Washington-Oregon	203
Western Gulf of Mexico	196
Mid-Atlantic	185
Beaufort Sea	183
Navarin Basin	131
Aleutian Basin	107
Bowers Basin	97

[a] Based largely on extent of coastal and marine habitats in planning area and sensitivity to effects of spilled oil.

SOURCE: Minerals Management Service, Draft Proposed Program, *5-Year Outer Continental Shelf Oil and Gas Leasing Program for Mid-1986 Through Mid-1991*, March 1985.

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[13] John M. Teal and Robert M. Howarth, "Oil Spill Studies: A Review of Ecological Effects," Environmental Management (1984), 8(1):27-44.

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oil contamination can decrease the abundance of organisms and the diversity of species of benthic communities. However, there are striking differences in sensitivities among these species. Persistent effects have been found in soft sediments in shallow, protected waters, where natural recovery may take 6 to 12 years or more. Rocky headlands are much more quickly cleansed, and generally recover within a few years, at least to the extent of recolonization of the substrate. Where initial recolonization is not by the normal dominant species, however, time for return to initial conditions through succession may be much greater.

Affected Species

Fish

The commercial fish stocks of the Bering Sea and Georges Bank are world-renowned. Important commercial fisheries exist in most other U.S. OCS areas as well, and subsistence fishing is important in the Beaufort, Chukchi, and Bering Seas and the Gulf of Alaska. In the Bering Sea, for example, lease sales have been held or are being planned in such productive fishing grounds as the North Aleutian Shelf, St. George Basin, and Navarin Basin. Important commercial fish species in these areas include: sockeye, chinook, chum, Pacific, pink, and coho salmon; Tanner and king crabs; Pacific herring; Pacific halibut; yellowfin, flathead, and rock sole; walleye pollack; Pacific cod; Greenland turbot; sablefish; Pacific Ocean perch; atka mackerel; arrowtooth flounder; sidestripe, pink, and humpy shrimp; and Alaska plaice. In addition to the United States, Japan, the Soviet Union, South Korea and several other nations regularly fish these waters. The 1983 ex-vessel (before processing) commercial value of the Bering Sea catch was about $409 million dollars.

The regional effects of oil spills on most species of fish are likely to be minor. It has been noted that:

> . . . although there is a widespread public perception of impending environmental degradation and resulting loss to harvestable populations coinciding with possible oil spills, this does not appear to be justified for relatively small oil spills . . . [b]ecause most species are widely dispersed in the Bering Sea and because stocks exhibit high annual variability in year class strengths. [E]ven the largest estimated oil-induced mortalities from spills occurring under open-water conditions would probably be undetectable in regional fisheries.[14]

However, species which spawn in nearshore areas in relatively few locations—for example, salmon, herring, capelin—could be particularly vulnerable to a large spill. A large oil spill in Bristol Bay, for instance, during a period in which salmon were migrating to their spawning grounds could have substantial effects on a large portion of a year class. Kills of adult fish probably pose less of a threat to commercial fisheries than do damage to eggs and larvae, or changes in the ecosystem supporting the fishery. The greatest potential effect on fish populations would probably occur if oil were spilled in spawning or nursery areas where larvae and eggs were abundant, or if local populations of food species of adults, juveniles, or larvae were reduced or eliminated.

Birds

Birds are particularly susceptible to the effects of oil spills and human interference. Depending on the time of year, large numbers may be present in Arctic areas. For example, at least six million marine birds breed on the Pribilof Islands and on St. Matthew and St. Lawrence Islands adjacent to the Navarin Basin.

Birds most vulnerable to oiling are those which are gregarious, spend much of their time on the surface, and dive rather than fly when disturbed. These include murres, puffins, and diving ducks such as eiders, scoters, and oldsquaws. Oiling of plumage may cause death from hypothermia, shock, or drowning. In addition, death of embryos may result from the transfer of oil on feathers to eggs. The physiological stress accompanying migration may reduce birds' ability to survive the additional stress resulting from oiling. Oil ingestion through preening could possibly reduce reproduction in some birds and causes various pathological conditions.

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[14] Fredrik V. Thorsteinson and Lyman K. Thorsteinson, "Fishery Resources," in Lyman K. Thorsteinson, Ed., *Proceedings of a Synthesis Meeting: The North Aleutian Shelf Environment and Possible Consequences of Offshore Oil and Gas Development* (Juneau, Alaska: Outer Continental Shelf Environment Assessment Program, March 1984), p. 153.

Oil spills occurring near colonies or along migration corridors could have substantial effects on seabirds and waterfowl. Oil reaching coastal wetlands could persist for a long period of time, and large numbers of birds could be contaminated. The MMS estimates, for instance, that important regional seabird populations on St. Matthew and adjacent islands could sustain major losses if spills occur in the area during the breeding season. MMS estimates that seabirds and waterfowl wintering in the Navarin Basin lease area may sustain losses of 10,000 or more birds in each of the several spills projected over the life of the field.[15] A tanker spill in Unimak Pass, one of the major migration corridors for bird and mammal populations entering and leaving the Bering Sea, could be particularly serious, since oil could potentially affect major portions of regional populations of both birds and marine mammals. However, long-term population responses of sea-birds to oil-induced mortalities are uncertain due to incomplete data. For example, Great Britain's seabird populations appear to be increasing in spite of incremental mortalities induced by OCS oil and gas operations in the North Sea.[16]

Marine Mammals

Impacts of potential oil spills on marine mammals have received considerable attention. Effects could include coating of animals with oil, ingestion of oil, and irritation of eyes. Contact with oil may also contribute to or alter susceptibility to existing physiological and/or behavioral stresses. However, "unequivocal evidence for mortality of marine mammals caused by oiling in the wild has not been observed."[17] The potential for adverse effects on most marine mammals from large and small oil spills is perceived to be low. Adverse effects in the immediate vicinity of a spill would be unavoidable, but, given the mobility and widespread distribution of most species, the low occurrence rate of large spills, the relatively small areas affected by spills, and the rapid dispersion and dilution of small spills, significant population losses of most species are unlikely.

Some species are probably more vulnerable than others, and some species may be particularly vulnerable at certain times of the year or while occupying certain habitats. Research to date suggests that the animals most at risk are those vulnerable to oiling of fur, such as furred seals, sea otters, and polar bears. A number of endangered and threatened species occur in prospective OCS development areas. Other cetaceans inhabiting subarctic seas during all or part of the year include right, fin, sei, blue, humpback, gray, and sperm whales. Some of these whales (for example, gray whales) migrate considerable distances, and may potentially come in contact with oil in several OCS regions.

Several examples of areas where marine mammals would be particularly vulnerable include:

St. Matthew Island. In addition to large seasonal concentrations of nesting birds, St. Matthew Island (and nearby Hall Island), is the location of numerous haulout sites for Stellar sea lions, spotted seals, and walruses. Several species of endangered whales also inhabit the vicinity. A support facility for Navarin Basin exploration and development has been proposed for this Bering Sea island; however, recent court action denied the facility. In addition to the possible impact of oil spills, marine mammals and birds in the area may be exposed to fre-

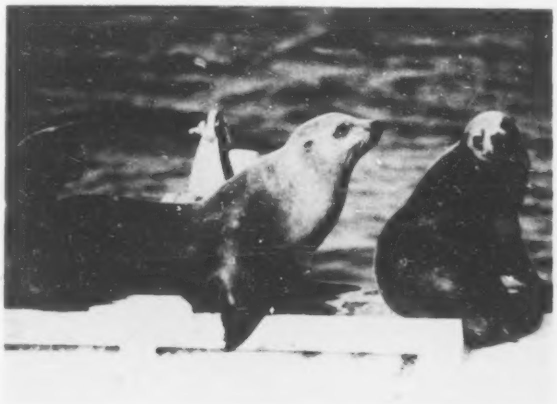

Photo credit: American Petroleum Institute

Offshore energy production must be balanced with protection of seals and other wildlife quent vessel movements, helicopter flights, and construction activities.

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[15] Minerals Management Service, *Navarin Basin Lease Offering: Final Environmental Impact Statement* (November 1983).

[16] Laurie Jarvela, Lyman Thorsteinson, and Mauri Pelto, "Oil and Gas Development and Related Issues," in Laurie Jarvela, Ed., *The Navarin Basin Environment and Possible Consequences of Planned Offshore Oil and Gas Development* (Juneau, Alaska: Outer Continental Shelf Environmental Assessment Program, May 1984).

[17] Minerals Management Service, *Navarin Basin Lease Offering: Final Environmental Impact Statement* (November 1983), p. IV-37.

The Pribilof Islands. In addition to their importance to nesting birds, from May through August the Pribilof Islands are home to over 70 percent of the world's population of northern fur seals, which breed and bear their pups there. Fur seals may be particularly sensitive to oiling since they rely on their fur for thermal protection, and oil can destroy its insulative properties. Oil spill trajectory models indicate that a St. George Basin spill could possibly reach the Pribilof Islands.[18]

Unimak Pass. Unimak Pass through the Aleutian Islands is a major migration corridor for endangered gray, fin, and humpback whales, northern fur seals, and several species of birds (e.g., shearwaters and tufted puffins). Although it is predicted that strong currents would likely rapidly wash away spilled oil, a spill large enough to significantly oil the pass in early spring or late fall could expose great numbers of whales, birds, and fur seals to hydrocarbons, and could seriously impact regional populations. In the event of oil and gas discoveries in the Bering Sea, increased vessel traffic (including tankers) is expected through the Pass.

Bowhead Whales: A Case Study

Introduction

Bowhead whales are listed as an endangered species and could be adversely affected by offshore oil and gas operations in the Arctic. The degree of their vulnerability remains uncertain at this time; however, bowheads are a subject of concern and the target of several expensive research projects. As a consequence of their endangered status, the Endangered Species Act places specific legal constraints on all Federal agency activity affecting the species. Thus, the potential impacts of offshore oil and gas activities on the bowhead population must be considered fully. If these activities are found to jeopardize the continued existence of bowheads or other endangered species, the law requires that actions be taken to ensure their preservation. Actions to protect bowhead whales could take the form of restrictions on or curtailment of Arctic oil and gas development. Thus, the potential for conflict exists between the competing national objectives of energy production and the preservation of an endangered species.

Bowhead whales are also highly prized by the indigenous people of the Arctic (the Inuit) as a supplementary source of food and as a part of their cultural heritage. Activities which threaten bowhead whales are considered by the Inuit to be a threat to their culture and their subsistence lifestyle. At the same time, the annual bowhead harvest by Inuit whalers may also be a threat to the existence of the species. The national effort to protect endangered marine mammals competes, to some degree, with the local interest in Arctic subsistence hunting. Protection of bowhead whales is thus complicated by competing national interests in the production of domestic energy and the desire to protect endangered species as well as by the interests of Native Alaskans to pursue their traditional lifestyle. The debate surrounding the bowhead whale involves complex scientific, political, and socioeconomic issues for which there are no totally satisfying answers.

Compared to a pre-exploitation whaling stock (estimated by the International Whaling Commission to be approximately 20,000 animals during the 1800s), the minimum population is now believed to be about 3,900. Census taking has improved in recent years, so that this number is larger than the number of whales believed to exist in 1977 (between 800 and 1,200 animals), but the figure is still imprecise. For hundreds of years, until about the turn of the century, bowheads were one of the most important commercial whale species. Commercial exploitation of bowheads has ceased, but whaling in several coastal Arctic native communities is still an important cultural activity.

Bowhead whales winter in the Bering Sea, generally south and west of St. Lawrence Island (the full extent of the area they use is unknown). In March and April they begin their northward migration, using the lead systems that develop in the ice cover. The whales follow nearshore open leads past Point Hope, Cape Lisburne, and Point Barrow and then move further offshore en route to their summer range in the eastern Beaufort Sea off Canada.

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[18] H. W. Braham et. al., "Marine Mammals," in M. J. Hameedi, Ed., *Proceedings of a Synthesis Meeting: The St. George Basin Environment and Possible Consequences of Planned Offshore Oil and Gas Development* (Juneau, Alaska: Outer Continental Shelf Environmental Assessment Program, March 1982).

After about mid-September the whales begin their return migration to the Bering Sea. The migration corridor is bounded on its landward side by approximately the 20-meter isobath and extends on its seaward side to at least the 50-meter isobath. It is during the migration periods when the whales are closest to the coast that they are hunted by Inuit (Eskimo) whalers and, at the same time, may be most vulnerable to potential disturbance by the activities of the oil and gas industry.

Concerned Groups

Among the groups with a stake in the future of the bowhead whale are the indigenous people of the Arctic (the Inuit Eskimos of Alaska), environmentalists, industry, the Federal Government, and the State of Alaska.

Inuit. For the Inuit, the bowhead whale is an important element of cultural identity. Despite the ongoing changes occuring in Alaska whaling villages, many traditional activities remain important, and the annual hunting cycle remains essentially the same as practiced for generations. Currently, ten Inuit villages participate in bowhead hunting. Eight of these ten villages take part in the spring hunt, and three participate in the fall hunt. Barrow, given its strategic location, is the only village to participate in both hunting seasons.

A recent survey indicates that most Inuit continue to value hunting and fishing highly and to view these activities as an important source of food.[19] Data from the same survey also suggest that Inuit still prefer locally harvested foods (especially whale meat, although seal and walrus are probably consumed in greater quantity) despite the influence of western culture. Inuit maintain that the 'Eskimo way of life' would be severely jeopardized if they could no longer hunt bowhead whales. In addition to the food that the whales provide (which is shared among the members of the community), a successful hunt is an occasion for celebration, a symbol of initiation into manhood, and brings prestige to successful whalers.

Photo credit: National Marine Fisheries Service

The endangered bowhead whale is important to the Inuit culture

Inuit are concerned about potential adverse impacts that offshore oil and gas activities could have on bowhead whales. They are concerned about maintaining a pollution-free marine environment, about protecting bowhead feeding and nursery areas, and about preventing seismic survey and other noise-making activities that may interfere with the annual hunt or with the health of the species. Increasing industrial activity in the Arctic highlights the fact that whale hunting now must compete with national, and even international, interests. These concerns have stimulated an active Inuit-sponsored research program to learn more about the factors which affect bowhead whales. This research focuses on bowhead population dynamics (size and growth rates) and on the possible susceptability to disturbance from various industrial activities.

Environmentalists. The primary concern of enviromentalists is for the protection and stewardship of an endangered species and its marine habitat. Environmentalists are particularly concerned that the projected increase in offshore oil and gas activities may be detrimental to the bowhead whale population. Offshore exploration and development introduces increased levels of industrial noise into the marine environment and raises the potential for marine oil pollution, both of which may be harmful to whales. Environmentalists assert that the effects of noise (particularly noise generated by marine seismic exploration) and of oil pollution on bowhead whales should be fully studied, and that steps should be taken to reduce impacts as much as possible.

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[19] Alaska Consultants, Inc., *Subsistence Study of Alaska Eskimo Whaling Villages* report prepared for the U.S. Department of the Interior (January 1984).

Most environmental groups are not enthusiastic about subsistence whaling, but tend to view it as a legitimate activity so long as vigilant oversight of bowhead stocks is maintained and traditional methods are used. A few groups have advocated the complete prohibition of native whaling of endangered whales. These groups contend that the result is the same whether the whale is taken by commercial whalers or native whalers. If the species is endangered, they reason, no whaling should be allowed.

Between 1970 and 1977, there was about a threefold increase in the bowhead whale harvest. In 1977, the International Whaling Commission noted this trend with alarm, and established a quota for native whalers which has been in effect since the 1978 harvests, reducing the hunt to approximate historic levels. This quota system is considered an important management tool by environmentalists and by the Federal Government.

Industry. The oil and gas industry acknowledges that under certain circumstances bowhead whales do respond to offshore hydrocarbon activities, but does not believe that normal operational activities constitute a major problem for the health of the whale stock. Even if some limited, localized, short-term impacts (e.g., flight response to nearby seismic activities) are unavoidable, the industry does not believe that long-term effects from oil and gas activities will be significant.

Seasonal drilling restrictions have been imposed and protective buffer zones established to mitigate the possible adverse impacts to bowhead whales. Industry's consistent opposition to these costly restrictions that reduce operating efficiency is based on their belief that they are not warranted by the scientific evidence. However, industry wishes to avoid unnecessary interruptions in its long-term operations, and has therefore participated in some bowhead research projects (for instance, by dedicating geophysical ship time to assess seismic impacts on bowhead whales).

The industry is convinced that, given current technology and personnel training, the possibility of a major blowout in the Arctic is remote, and that even if such an accident were to occur, the capability to recover most spilled oil and thus to avoid harm to whales, is adequate. Since the first stipulations attached to the 1979 joint Federal/State lease sale in the Beaufort Sea, lease stipulations inside the barrier islands have become less stringent. However, industry is still unhappy with seasonal drilling restrictions.

The Federal Government. The Federal Government is responsible for promoting OCS development, protecting endangered species, and ensuring that Native interests are considered. The desire to stimulate domestic petroleum production was the primary reason for the Administration's decision to accelerate leasing of OCS lands. In addition, the sale of leases for OCS energy exploitation is the second-ranked source of Federal revenues, and OCS resources are seen as insurance against potential international energy supply disruptions.

Federal development and protection objectives are potentially in conflict, particularly since leasing is now taking place at a faster pace in Alaskan offshore areas. However, several Federal laws provide for the protection and management of bowhead whales. The Endangered Species Act of 1973 prohibits the taking, harassing, importing, exporting, or interstate trading of any endangered species, their parts or products. However, the take by Alaska natives is exempted. The Marine Mammal Protection Act of 1972 protects all marine mammals from any undue influence or exploitation by U.S. nationals and forbids importation of any marine mammal products into the country. "Subsistence" hunting is permitted as long as the stocks can support the harvest, and specific conditions are met.

The Endangered Species Act specifies that it is the responsibility of all Federal agencies to conserve endangered species. Each Federal agency is required to ensure, in consultation with the Fish and Wildlife Service or the NMFS (as appropriate, for species under their respective jurisdictions), that any action it authorizes, funds, or conducts is not likely to jeopardize the continued existence of an endangered or threatened species or result in the adverse modification of its critical habitat. Thus, MMS must consult with the NMFS on the probable impacts to bowhead whales that might result from many OCS activities for which it issues permits. NMFS then issues a biological opinion concerning the likelihood that these impacts will jeopardize the survival of the species. If so, NMFS also describes "reasonable and prudent alternatives" to the activity that would avoid jeopardy.

In practice, NMFS also includes in its biological opinions recommendations and suggestions that it feels would help conserve the species, although the Act does not require that they be included. MMS is not legally required to adopt these recommendations, suggestions or alternatives to avoid jeopardy so long as the mitigating measures it does adopt are consistent with the alternatives, would effectively preclude jeopardy, and satisfy the intent of the law.

Some dispute the right of the MMS *not* to accept all parts of biological opinions. DOI's 'veto power' has been criticized by those who contend that NMFS recommendations should be binding. However, biological opinions carry weight in the courts, so DOI must have good reasons for not implementing every NMFS recommendation or risk being litigated. The biological opinion process has evolved over the years, and NMFS recommendations for avoiding jeopardy to the species are less specific than they once were.

In 1981, the NOAA and the Alaska Eskimo Whaling Commission signed a cooperative agreement to implement the limited bowhead quota allowed by the International Whaling Commission (IWC). For calendar years 1981, 1982, and 1983, a quota was established by the IWC for the Bering/Beaufort/Chukchi Sea stock of 45 bowheads landed and 65 struck, with a maximum of 17 to be landed in any one year.[20] (65 whales were struck, and, of these, 34 were landed). For 1984 and 1985, 43 strikes have been allowed (0.55 percent of the estimated population per year), but no more than 27 can be made in either year. The agreement specifies whaling techniques, monitoring procedures, and division of responsibilities.

Alaska. The State must consider the welfare of its citizens, and, in this particular case, the welfare of those engaged in native whaling. Similarly, the State is concerned with environmental protection. Moreover, since the State derives a major proportion of its revenues from the oil and gas industry (although none at the present time from Federal OCS leases), it has a major stake in fostering responsible oil and gas development. These interests may be conflicting if oil spills or industrial noise associated with development adversely affect the environment or Native hunting.

The State believes that further research should be undertaken. The State also is concerned about the capability of industry to clean up oil spills and about the effects of such spills on bowhead whales. For these reasons, in responding to the Draft Environmental Impact Statement for the 1984 Diapir Field Sale No. 87, the State of Alaska recommended that sensitive blocks in the eastern and western parts of the sale area be deleted and that all proposed stipulations in the DEIS be adopted. In general, the State believes that mitigating measures are preferable to tract deletions if adequate scientific information is available or if existing technological capabilities are adequate; however, it was not felt at that time that these concerns had been adequately studied.

More recently, the State's position regarding bowhead whales was addressed in its decision to allow exploratory drilling in the Beaufort Sea where the capability to clean up oil spills in broken ice can be demonstrated. However, in reaching its decision to allow longer drilling periods in certain circumstances, the State reviewed existing bowhead whale and related knowledge and concluded that: 1) the likelihood of a large oil spill from exploratory drilling was small; 2) the probability that migrating bowhead whales would encounter spilled oil was also small; 3) oil spill countermeasures for combating spills from artificial islands are now adequate; and 4) prohibition of exploratory drilling and other downhole activity during whale migrations is an adequate measure to ensure that bowheads are not unduly disturbed by industrial noise. The State recognizes that information gaps still exist and that its decision was based on a large amount of probabilistic data, but it is satisfied that exploratory activities in nearshore areas can be conducted without significant impacts on bowhead whales.

Potential Impacts

The June 1984 Diapir Field Final Environmental Impact Statement for Sale No. 87 and accompanying comments on the Draft Environmental Impact Statement provide an overview of the current state of knowledge concerning the impacts of oil and gas development on the bowhead whale.

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[20] William F. Gusey, *Bowhead* (Houston, Texas: Shell Oil Company, June 1983), p. 87.

Noise. Bowheads may react to noise associated with offshore activities. The ocean is naturally noisy owing to sounds created by rain, wind, ice, and the animals themselves. However, noise pollution has been of concern in recent years because some marine mammal species seem to rely heavily upon sound for communications with one another and for acquiring information about their surroundings. Since many offshore industrial activities create intense sounds, there has been concern that such sounds may disturb marine mammals and also mask the "natural" sounds that are apparently important to these mammals. In evaluating the potential effects of noise from industrial operations, it is important to consider ambient noise levels, the characteristics of noise from industry sources and from marine mammals, the propagation of sound in water, hearing by marine mammals, the "zone of influence" of noise from industry sources, and documented reactions of marine mammals to industrial noise.[21]

Sound can be generated by passing boats and ships, by open-water geophysical seismic exploration, and by on-ice activities or onshore installations. The intermittent sound generated by seismic surveys is the most intense type of sound. Short-term behavioral reactions to seismic activity and vessels may include flight from the area, changes in surfacing and dive times, and temporary changes in direction. However, responses of bowheads to seismic activity have been much less clear-cut than responses of bowheads to moving vessels.

Evidence demonstrates that bowheads react to low-flying aircraft by diving suddenly and thus are sensitive to aircraft disturbance. Other sources of noise include drilling activities and dredging and gravel island construction, none of which is expected to be as disturbing to whales as vessel noise. Adding the small effects of all these noise disturbances together, MMS has concluded that during the spring and fall migratory period, noise from seismic activity on leased tracts or from vessels or aircraft could have moderate impacts on bowheads. That is, a portion of the regional population could change in abundance and/or distribution over more than one generation, but is unlikely to affect the regional population. The North Slope Borough and many environmental groups disagree with this overall conclusion, and believe that MMS has tended to downplay evidence suggesting greater effects.

Oil pollution. Few observations of the responses of bowhead and other whales to oil spills have been made. It is unknown whether or not large cetaceans are able to detect hydrocarbon pollution. Dolphins, however, have shown an ability to detect and avoid oil. The rough nature of bowhead whale skin suggests that bowheads may be more vulnerable to affects of surface contact with oil than most cetaceans. Concern has also been expressed that bowhead skin and eyes may be sensitive to oil contact, but it is unknown whether contact would be harmful. Inhalation of toxic substances and plugging of blowholes by oil have also been cited as possible, but unlikely, threats.

The potential effect of oil on bowhead feeding is another type of adverse impact. Bowheads may not be able to differentiate between hydrocarbon-contaminated and uncontaminated food. If the baleen plates of bowhead whales become fouled by oil, feeding efficiency is decreased, although recent experiments have shown only minor and short-lived reductions in efficiency. Indirectly, bowheads may be adversely affected if food sources are reduced by acute or chronic hydrocarbon pollution, but such pollution would have to be very widespread in order to have a serious effect.

The impact of an oil spill on the bowhead whale population would vary depending upon the volume of oil spilled, the amount of oil in the water column, the extent of weathering of the oil, the proportions of habitat affected, the numbers of whales present, and other factors. The MMS considers the probability that oil from an accidental spill will come in contact with whales in the offshore leads to be very low, particularly "since whales are not present in the lease offerings at all times, and if certain tracts are deleted from lease consideration."[22]

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[21] W. J. Richardson et. al., *Effects of Offshore Petroleum Operations on Cold Water Marine Mammals* (American Petroleum Institute, October 1983).

[22] Minerals Management Service, *Diapir Field Lease Offering: Final Environmental Impact Statement* (March 1984), p. IV-100.

MMS concedes that localized effects of spills could occur, but believes that the probable degree of regional impact from oilspills within the lease area will be minor. Other groups believe the impact could be severe in the case of a major oil spill, and the NMFS, as noted above, has concluded that an uncontrolled blowout or major oil spill could jeopardize the continued existence of the species if whales are present and encounter spilled oil.

In the Final Environmental Impact Statement for the August 1984 Diapir Field lease sale, MMS concluded that the overall regional impact of the combined effects of noise and oilspills resulting from the original proposal was not expected to exceed "moderate." Moreover, if sensitive tracts in the western and eastern portions of the Diapir Field sale area were deleted, the combined potential adverse effects on bowhead whales were expected by MMS to be minor. Both the State of Alaska and the North Slope Borough supported these tract deletions in order to reduce potential disturbances to the whales in the spring ice lead system and during the fall migration offshore of Point Barrow. As a result, a 20-mile buffer zone was established around Barrow, where the Inuit conduct their hunt; and, although no tracts were deleted in the eastern Beaufort Sea, a study has been initiated to determine whether this area is an important habitat where oil and gas exploitation should be restricted. Borough residents believe this is a major improvement over the original lease plan.[23]

While the MMS bases its conclusions on the best available information, there are still gaps in knowledge about bowhead whales. Hence, despite the fact that bowhead whales have been one of the most studied of the endangered species, there is still disagreement concerning the probable effects of oil, noise, and other aspects of human intervention on the behavior, survival, and reproduction of individuals and populations.[24]

Research Priorities

Four general areas for future research appear to be especially important.

Population studies. There is a continuing need for more precise information about the status of the bowhead whale population. Shore-based censuses, aerial surveys, and/or acoustical detection methods have been employed in bowhead whale population studies for about 8 years, yet scientists still have not satisfactorily defined population parameters. Reliable information is needed about the current and the historic distribution, abundance, and productivity of the population. Currently, it is believed that calves account for at least 7 percent of the population, and that the distribution among age classes is about normal. However, it is not yet known whether the bowhead population is growing, stabilized, or decreasing or what the natural mortality rate is. Such information is important in order to determine population status and trends to aid in conserving the species. It is also important to facilitate setting quotas for Native whalers. Thus, if the yearly increment in the bowhead population can be accurately determined, it will be possible to allocate, with a much larger degree of confidence, a portion (e.g., one-half) of this increment to native hunters.

One hypothesis that has been put forth recently is that the Beaufort Sea bowhead whale population may be a distinct sub-population or feeding group. While feeding groups in the Chukchi and Bering Seas have been decimated, the Beaufort Sea stock may, in fact, be healthy and possibly as numerous as before commercial whaling began. This hypothesis will be difficult to test; however, historical data make it clear that large numbers of bowheads once existed in the Bering and Chukchi Seas in June, July and August. Thus, of an original western Arctic bowhead population of perhaps 20,000 animals, it has been suggested that only one-quarter to one-third of these animals comprised the Beaufort Sea sub-population. Since there are now known to be a minimum of 3,900 bowhead whales, the present stock may be very near historical levels. Thus, as a corollary of this hypothesis, until the Bering and Chukchi stocks can be repopulated, one cannot expect the bowhead population to recover, because it involves distinct sub-populations. If this hypothesis can be proven, rethinking of bowhead whale stock management would be in order.

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[23] "Plans for Oil Leases Would Protect Whales," The New York Times (August 5, 1984), p. 27.

[24] L. Lee Eberhardt and R. J. Hofman, "Existing Programs, Technology, and Requirements Relative to the Conservation and Protection of Marine Mammals in the U. S. Fishery Conservation Zone and in the Southern Ocean," in *Technology and Oceanography* (Washington, DC: Office of Technology Assessment, 1981).

Effects of noise. Better understanding of these effects will aid in establishing appropriate "zones of influence," thereby enabling better protection of the whales from noise associated with industrial activities. If one knows the noise levels of an industrial activity and the propagation characteristics of the surrounding waters, then it is possible to determine how far the sound travels and its level of impact at various distances from the source. It is much more difficult to determine the effect of noise on the whale, in large part because it is difficult to control all aspects of experiments. Results from the most recent study have shown that whales do not exhibit avoidance behavior beyond four miles from seismic activities, and that behavioral changes between about 2 and 4 miles are only temporary.[25] Although the presence of whales in the vicinity of industrial activities in the Canadian Beaufort has declined since 1980, evidence proving a cause and effect relationship between industrial activities and the decline has not been established. Canadian efforts to address this question are currently underway.

If bowhead whales have a threshold level above which noise causes detrimental effects, then a zone of influence—generally delimited by a circle—can be calculated. The zone delimits the area within which activities (e.g., seismic activity) may be restricted when whales are present. Several zones may be postulated, the size of which vary according to the level of sound and/or the degree of disturbance; however, with currently available information, determining zones of influence may be a theoretical exercise. MMS has established a 5-mile zone of influence, pending receipt of new data. The NMFS concurs with this decision. Both agencies feel that more information is necessary, however, and MMS has established an experimental program with cooperating oil and geophysical exploration companies to obtain more data concerning whale reactions to seismic activities.

Cumulative effects of industrial activities. Such effects are extremely difficult to assess, particularly in the absence of development. However, it is important to know whether whales are likely to permanently vacate oil and gas development areas or whether they might, in fact, become accustomed to development activities as seems to be the case with gray whales in Southern California. In addition, as offshore Arctic development increases, whales are likely to encounter more industrial activity. Thus, it is possible that noise and pollution effects, which, in isolation, may not be detrimental, may have a cumulative impact as whales encounter these effects along their migratory route.

Identification of sensitive habitats, including primary feeding areas and nursery areas within U.S. and Canadian waters. Migrating bowheads in spring do not feed extensively. However, there is new, but as yet unsubstantiated evidence that the area between Barter Island and the Canadian border is an important habitat area where bowhead whales feed on their westward fall migration. Concern has been expressed by the North Slope Borough and other groups that seismic and oil activities in this area may adversely affect bowhead feeding at a critical time and, hence, that the bowhead population may be affected. Scientists would like to be able to correlate the distribution of organisms in these areas with whale feeding habits. In 1985, MMS plans to study the importance of the area east of Barter Island to bowhead whale feeding. Better knowledge of feeding areas will aid understanding of migratory patterns and in conservation of the whale's ecosystem.

Some specific tasks have been identified by the Interorganization Bowhead Whale Research Planning and Technical Coordination Group.[26] The group agreed that the highest priority short-term (1983) research needs included:

- Continuation of studies of recruitment using photography.
- Completion of the evaluation of the sources of bias in census taking and improvement of the accuracy of the census count (at Point Barrow).
- Study of the distribution of bowheads in summer to facilitate estimating total abundance and migratory behavior.

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[25] Minerals Management Service, "Observations on the Behavior of Bowhead Whales in the Presence of Operating Seismic Exploration Vessels in the Alaskan Beaufort Sea" (Technical Report, 1985).

[26] National Marine Fisheries Service, "Report of the Second Interorganization Bowhead Whale Research Planning and Technical Coordination Meeting" (Washington, DC: NOAA Technical Memorandum, April 1983).

- Identification and evaluation of possible feeding areas in the Beaufort Sea in summer and autumn.
- Determination of the effects of seismic operations (through a boat-whale interaction study).
- Initiation of a review of the state-of-the-art of bowhead knowledge.

This last task is important because there has been a rapid accumulation of information in the past few years, but a much slower rate of synthesis. Moreover, it could be a very useful exercise in order to reach a scientific consensus on the key issues. Other important but less pressing studies were also identified by the group.

Current Research

Research on bowhead whales is conducted by several organizations, but primarily MMS. MMS is conducting surveys to detect when whales are present in areas where they could be disturbed by seismic activities. They are also doing basic behavior and perturbation studies, and, in the Bering Sea, distribution and abundance studies. Since 1980, MMS has funded four studies related totally or in part to the effects of noise on endangered whales. The funding for these studies through 1983 was about $4.3 million.

NMFS is responsible for the management of bowhead whales. The National Marine Mammal Laboratory in Seattle, Washington, is involved in bowhead whale research. NMFS research focuses on understanding the life history and population dynamics of bowhead whales. During the spring migrations, bowheads are counted from ice camps, and during the summer photo-identification surveys are conducted.

The North Slope Borough and Alaska Eskimo Whaling Commission receive much of their research funds from the Alaska Legislature. Their research focuses on biological studies of animals taken in harvest. They have also conducted population counts of bowheads as they move north in the spring. Recently, hydrophones have been used at the counting stations to try to account for the whales which pass beyond the view of visual counters or travel when the leads are closed. The North Slope Borough has organized and convened several bowhead whale symposia.

The oil industry also has contributed to the bowhead whale research effort. Particularly valuable was the large research effort undertaken in 1981 which led to the discovery of a better means to estimate the rate of calf production.

In comparison to the funds spent on other endangered species, a large proportion of available money has been spent on bowhead research. In large part, this is due to expensive logistical requirements, and to the necessity of using ships and airplanes. Despite the large sums of money that have been spent, most scientists are reluctant to make unqualified statements concerning bowhead whale population, reproduction, or the effects of noise and oil contamination.

The reasons for large bowhead whale research budgets are at least in part political. Native Alaskans hope that research results will help them both to justify a continued, if not expanded, whale hunt and to protect the health of the species. The oil industry hopes that research results may lead to less restrictive stipulations, and the Federal Government must try to balance competing national and international objectives. In addition, the special status of bowhead whale research stems in part from the legal mandate granted by the 1973 Endangered Species Act and the 1972 Marine Mammal Protection Act.

Operational Restrictions

MMS can mitigate potential adverse impacts that oil and gas activities may have on bowheads by deleting tracts or by specifying lease stipulations and conditions in operating permits, some of which NMFS suggests in its biological opinion. These may take the form of drilling restrictions during migration or broken ice periods, restrictions on seismic activities when whales are within the vicinity (e.g., within a 5-mile zone of influence), and/or directions to vessel operators on how to comport themselves in the presence of whales. For instance, in the 1979 Federal/State Beaufort Sea Lease Sale the recommendations of scientists were followed and a 7-month seasonal drilling closure effective for 2 years was proclaimed. In the 1982 Diapir Field lease sale, drilling restrictions were reduced so as to apply only to specified tracts and only during the 2-month fall whale migration. Moreover, MMS did not adopt NMFS's recommendations in its biological opinion calling for drilling restriction periods to be extended so as to ensure that areas occupied by migrating whales are free of oil by the time the whales arrive. MMS did not believe that the low level of risk of a major oil blowout or spill during exploration justified such a precaution. In the 1984 sale, drilling and other downhole activity has been restricted in the periods of April 15 through June 15 and September 1 through October 31 in the western blocks and between August 1 and October 31 in the eastern blocks.

MMS may also publish a "notice to lesees and operators." This is advisory and applies to those activities which take place after the lease sale but before development or production plans are submitted. For instance, MMS may advise lessees to use aircraft to ensure that no bowhead whales are within 5 miles of seismic operations.

The findings of bowhead whale researchers have influenced Federal OCS lease decisions and stipulations in the past. Differences of opinion exist, however, concerning whether science or political considerations are more important in determining mitigating measures. Some scientists have suggested that "political issues and [especially] the desire to accelerate development on the OCS predominated over scientific considerations in the [1982] sale."[27] For instance, bowhead whale migration data were collected between 1979 and 1982, but, in the view of these scientists, the new data did not justify relaxing the seasonal drilling restriction. Conversely, much more data were available by 1982—it was clear by then, for instance, that the spring migration takes places well offshore and that the fall migration corridor lies in water from 20 to 50 meters deep—and restrictions were reduced in light of this new information.

Stipulations currently in place to mitigate impacts on bowhead whales are operational in nature, i.e., they affect operating procedures. Alternatively, one might consider stipulations requiring the design of offshore structures and ships aimed at reducing industrial noise to an acceptable level. Rather than being required to curtail activities in the presence of whales, industry could be offered an opportunity to design, for example, quieter ships. This regulatory approach is favored by some environmentalists, but they admit that far too little information is currently available for designing appropriately quiet technology, particularly given the lack of knowledge on the effects of noise on marine mammals. Moreover, designation of this type of stipulation would probably be beyond the current authority of the MMS. However, if such design regulations proved to be less costly to the oil industry than operating restrictions, industry may be receptive.

Current policies regarding protection of bowhead whales from the impacts of oil and gas activities and native whaling include limited and closely controlled Inuit hunting, stipulations controlling drilling and other activities during specified periods, and continuation of relevant scientific research. The aim of these policies has been to balance competing national interests. However, differences of opinion persist concerning their adequacy. Both the North Slope Borough and the environmentalists have pushed for greater bowhead whale protection, while the oil and gas industry believes drilling restrictions to be unwarranted based on the information available concerning whale migrations and on the safety record of OCS operations. Some alteration and/or finetuning of existing policies (e.g., alteration of whale quotas, changes in the radius of the zone of influence, or further tract deletions) may be necessary, depending upon the results of further scientific research. However, no significant changes of policy are likely to be necessary in the near term.

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[27] Jacqueline Grebmeier, "The Role of Science in the Alaskan Outer Continental Shelf Oil and Gas Leasing Decision Process" (Master's Thesis, Institute for Marine Studies, University of Washington, August 1983).

OIL SPILLS

Introduction

As the U.S. oil and gas industry begins exploration of deepwater and Arctic OCS areas, questions are being raised concerning the effectiveness of techniques and equipment for combatting oil spills in frontier areas. Industry argues that it is prepared for the possibility of spills in both Arctic and deepwater areas, and that the risk of catastrophic spills is very low. Although the petroleum industry has not had a drilling or production-related oil spill in U.S. waters as large as the Santa Barbara blowout since 1969, major spills in other parts of the world (for example the 1979 Ixtoc 1 blowout in the Gulf of Mexico) and a number of sizeable tanker casualties have heightened the public's awareness of the risks and consequences of oil spills.

The offshore oil and gas industry has a good oil spill prevention record. However, the industry has little experience producing oil in Arctic and deepwater frontier areas. With the exception of Canadian and North Sea operations and Cook Inlet operations in State waters in Southern Alaska, the industry's offshore operating experience and oil spill data are derived largely from operations in temperate regions, such as the Gulf of Mexico and California. Notwithstanding the oil and gas industry's plans and preparations for oil spills, it is still uncertain whether the industry will be able to make effective use of currently available equipment and countermeasure strategies to recover significant amounts of spilled oil in frontier areas. Although industry has equipment on hand and can airlift additional equipment to a spill site if necessary, this equipment has never been proven under realistic, at-sea conditions.

Most oil spill containment and cleanup technology has been developed for nearshore and temperate regions and may be unsuitable for Arctic or deepwater areas. Arctic oil spill countermeasures may be complicated by extremely cold temperatures, the presence of ice, long periods of darkness, intense storms, and lack of support facilities in most areas. Hence, the risk of oil spills in the Arctic may sometimes be greater than the risk in temperate areas. At least partially offsetting this factor, however, is the higher level of engineering in the Arctic and the significant attention paid to safety factors. Risks have been analyzed and are carefully considered in the planning process, but there is little offshore Arctic operating experience on which to base risk estimates. In deepwater areas, high seastates may be encountered, and the greater distance from shore may create logistical problems for oil spill cleanup. Existing cleanup technologies have proven effective only in placid, protected waters.

The number of frontier area spills that may occur, and, therefore, the total amount of oil that may be spilled is related to the amount of oil that will be found and produced. Predictions concerning the amount of oil frontier areas will yield are considered highly speculative, and thus the possible danger of oil spills is also uncertain. MMS uses oil spill risk analyses to estimate the probability of oil spills occurring in offshore areas it proposes to lease. Based on historic data from the U.S. OCS, MMS has determined that 3.9 spills of 1,000 barrels or greater and 1.8 spills of 10,000 barrels or greater can be expected for each billion barrels of oil produced and transported. Predicted spill types and corresponding rates are shown in table 7-2. Although no oil has yet been produced from the Federal Arctic OCS, and the United States has only recently begun production from areas of about 1,000-foot water depths, the probability that one or more spills of both 1,000 barrels or greater and 10,000 barrels or greater will occur over the productive life of each lease sale area is considered to be very high, based on past statistics.[28]

Table 7-2.—Oil Spill Probabilities
(predicted spills per billion barrels of oil produced)

Source of spills	1,000-barrel oil spills	10,000-barrel oil spills
Platforms	1.0	0.44
Pipelines	1.6	0.67
Tankers at sea	0.9	0.50
Tankers in port	0.4	0.15
Total	3.9	1.76

SOURCE: Minerals Management Service, *Navarin Basin Lease Offering: Final Environmental Impact Statement*, November 1983.

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[28] Minerals Management Service, *Navarin Basin Lease Offering: Final Environmental Impact Statement* (November 1983), p. IV-4.

Industry's capability to effectively deal with spilled oil in the frontier regions depends on two factors: 1) preparedness with regard to countermeasures strategies, logistical support, equipment availability, and planning; and 2) performance, effectiveness, and suitability of the containment and cleanup equipment. Industry has met current State and Federal requirements for pre-spill preparation. The major uncertainty, however, is how equipment which is currently available will actually perform under the conditions commonly encountered in Arctic and deepwater areas. Although the state-of-the-art of cleanup technology has advanced in recent years, for the most part, only rough qualitative measures of its effectiveness exist. Little quantitative data about equipment performance exists, and most of that which does exist is derived from relatively inexpensive and easily controllable simulations and small-scale tank tests rather than from expensive testing under real-life conditions. In many instances, the manufacturer's claims and the vendor's specifications are all the information available to gauge the effectiveness of the equipment.

There are two major types of oil spills: blowouts and tanker spills. The sudden, uncontrolled escape of hydrocarbons from a well is known as a blowout. Oil well blowouts differ from tanker spills in that the discharge rate of a blowout is often slower and usually occurs over a longer period of time. Tanker spills could involve the release of a large amount of oil over a relatively short period of time. The behavior of the discharge, countermeasures strategies, and the potential impact of a blowout spill are thus different than for tanker spills. Countermeasures strategies vary for blowouts depending upon the depth of the blowout (e.g., whether it is a surface blowout from an artificial island or a shallow or deepwater blowout resulting from a drillship accident), the amount and stability of ice cover (e.g., moving pack ice, broken ice, or open water), and the sea state.

If a blowout cannot be controlled quickly, large quantities of oil and gas may be released. If the blowout occurs on the sea floor, the difficulties of control are compounded; and if it occurs underwater *and* under moving ice, it can be extremely difficult to control. It has been estimated that an uncontrolled sub-sea blowout in the Beaufort Sea lasting one year (although improbable) could release about 500,000 barrels of oil.

Some characteristics of blowouts make them easier to handle than tanker spills. First, potential spill locations are known; thus, spill containment and cleanup equipment can be prepositioned and variables affecting the spill's behavior (currents, wind patterns, etc.) can be studied before the event. Second, the release rates of blowouts are generally lower than release rates of tanker spills. If a blowout can be quickly controlled, relatively less equipment may be needed to clean up this type of spill. And third, oil from a blowout is often initially in a fresh, fluid state. This characteristic makes cleanup easier. However, the oil does not remain fresh for long, and once it has weathered, it is more difficult to recover.[29]

There have been several proposals to transport Arctic hydrocarbons by ice-strengthened or ice-breaking tankers. The proponents of these proposals (e.g., Dome Petroleum) have designed tankers to minimize the risk of a spill. Nevertheless, the possibility of a tanker spill in the Arctic—if and when tankering becomes viable—cannot be discounted. It is impossible to predict the exact location of tanker spills. Equipment cannot be positioned in advance, and it is therefore very difficult to implement a fast response before extensive oil spreading and weathering occurs. Tanker spills may result in the release of a large amount of oil during a short period of time. Responses to such spills would require a large amount of equipment and manpower.

Limits to Effective Countermeasures

Environmental Variables

Whether a spill is from a blowout or a tanker accident, a number of environmental variables will affect the response effort. One of the most important is the amount of ice present. Spills may occur either in open water, under conditions of partial ice coverage, or in solid landfast or pack ice. Those which occur in complete ice cover are probably the easiest to control. In such instances, the most practical countermeasures technique currently available probably is to burn the oil on the surface of the ice or, if spilled under the ice, to burn it as it accumulates in melt pools during the spring breakup. Open water spills, particularly in the high sea states common in the Bering Sea, are much more difficult to clean up. For instance, contamination from a summer tanker spill is not likely to be significantly reduced using currently available cleanup technology. High sea states would, however, promote natural dispersion.

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[29] See S. L. Ross Environmental Research Limited, *Potential Large Oil Spills Offshore Canada and Possible Response Strategies* (Environment Canada, March 1982), *Oil Spill Countermeasures: The Beaufort Sea and the Search for Oil* (Canadian Department of Fisheries and the Environment, 1977), and *Evaluation of Industry's Oil Spill Countermeasures Capability in Broken Ice Conditions in the Alaskan Beaufort Sea* (Alaskan Department of Environmental Conservation, September 1983).

In many ways, however, the most difficult spills to clean up may be those which occur in partial ice cover. Most oil spill containment and cleanup technology has been developed for temperate region spills and may not be sufficiently effective when used in partial (or broken) ice. Some promising techniques have been developed recently, but all require further development, testing, and integration into an overall response strategy. The broken-ice period varies by year and by location. In the Beaufort Sea and Chukchi Seas, this period lasts approximately 3 to 7 weeks during breakup and 3 to 6 weeks during freezeup. Thus, the most difficult conditions in which to clean up spilled oil last from 6 to 13 weeks each year. A generalization about the Bering Sea is not possible since the Bering varies in climate from north to south. Some areas of the Bering Sea may have broken ice at any time of the year.

Other environmental variables also affect the performance and efficiency of equipment and the overall response effort. The velocity of the ice is important, since it is much more difficult to operate in moving ice than in stationary (or landfast) ice. The characteristics of the ice are also important. Solid ice, for instance, provides an excellent platform from which to stage countermeasures, but it is extremely difficult to maneuver equipment (such as barges or skimmers) when ice coverage is extensive. Conversely, the operation of equipment in old "rotten" ice or in thin, early season "grease" ice is probably easier than in solid ice, but these types of ice cannot be used as a countermeasures platform.

Inasmuch as the wind speed, sea state, and current strength affect both the rate at which oil is dispersed and the deployment and operation of countermeasures equipment, cleanup efficiency is also influenced by these variables. Water temperature also plays a role because colder temperatures increase the viscosity of the oil, thus reducing spreading. However, in very viscous oil mechanical cleanup is difficult, and the effectiveness of chemical dispersants is reduced.

Lack of Support Facilities

The absence of roads and support facilities throughout much of the North Slope and Western Alaska will make oil spill countermeasures difficult even if appropriate cleanup technology is available. There are few roads in these areas. Thus, land access to staging areas for offshore spills and/or threatened shorelines is rarely possible, and extensive use of aircraft is required. In addition there are no refineries, little manpower, few housing facilities, and few disposal sites. Some of the resources which could be mobilized in more populated areas in the event of a major spill simply do not exist in the Arctic. Conversely, industry argues that because Arctic areas are so remote, they must be self-sufficient. Located in the Prudhoe Bay area are fixed wing aircraft, helicopters, air cushion vehicles, roligons, trucks, boats, barges and personnel which could be mobilized rapidly in a local emergency.

Difficult Working Conditions

Difficult working conditions pose a general limitation on the capability of industry to clean up offshore Arctic oil spills. Although techniques, equipment, and clothing have been developed to minimize the effects of intense cold, and personnel have received specialized training, human efficiency is reduced in cold climates, and safety is correspondingly more difficult to ensure. Even with the best of protection, it is not possible to work outside for long periods of time. Generally, responses to accidents in cold environments take more time and equipment problems are greater, although little reliable data exists concerning the precise effects of cold on either human or equipment efficiency. The possibility that a spill may occur during the long Arctic night or during times of persistent fog also poses problems of efficiency industry will be able to make effective use of currently available equipment and countermeasure strategies to recover significant amounts of spilled oil in frontier areas.

Response Time

Of all the difficulties associated with containing and cleaning up spilled oil in the Arctic, two appear to be especially troublesome. The first is the problem of response time. Although inventories of oil spill cleanup equipment are located at Prudhoe Bay and at Dutch Harbor, response time is a problem because Arctic spills may occur in remote areas and because human efficiency is less in cold environments. If response to a spill is not prompt, the effectiveness of countermeasures is reduced, sometimes markedly. The response time problem will be particularly difficult in the case of tanker spills, since a spill may occur anywhere. Although tankers are not currently being utilized, their use in the Bering Sea can be foreseen, and their future use in the Beaufort and Chukchi Seas is being considered. It has been suggested that the major countermeasures question in the case of open water spills is how to deliver the technologies to the spill site prior to the oil's spreading and weathering beyond control.

In the Bering Sea, a distressed ship could be 400 or more miles from any point in Alaska and a much greater distance from a base that could support a spill response effort. For instance, it would take a Coast Guard icebreaker stationed at Kodiak Island at least 4 days to reach the site of a Bering Sea spill. It may be possible, if the safety of the crew is not at risk, to use the tanker itself as a working platform for countermeasures operations. A portable response system may be developed to be carried on tankers that would include booms that could be deployed by a small boat, skimmers that could be operated remotely or from the ship, and some kind of vehicle capable of operating in the water and on all kinds of ice. The United States has no requirement at this time that ships be equipped for countermeasures activities.

While the response time problem for remote tanker spills is of particular concern, responses to all Arctic spills will, on average, take more time than responses to temperate spills. The difficulty of detecting oil spills compounds the problem. Detection is most difficult for spills which occur under the ice or in broken ice, but it can also be a problem in more controllable situations, such as in the June 1981 Challenge Island oil spill in the Beaufort Sea. In this case a spill of approximately 3,000 gallons went undetected for an indeterminate length of time because of sustained inclement weather conditions.[30]

The industry treats the response problem seriously. Individual oil companies as well as industry cooperatives have stockpiled spill countermeasures equipment as required by the MMS. The companies prepare oil spill contingency plans for all exploration activities, and they conduct periodic drills to improve their response capability. In addition, the U.S. Coast Guard has established a national strike force equipped to respond to spills on short notice.

The broader countermeasures challenge is to develop a comprehensive and integrated spill response system. Such a system is composed of many components, including detection and surveillance, logistics operations, containment, recovery, storage, and disposal. In addition, the response operation depends upon timely weather and ice information and on other contingency plans (e.g., when conditions become hazardous, evacuation of personnel must be provided). If attention to any of the system components is less than adequate, the effectiveness of the overall response is likely to be limited. Thus, even with the best recovery technology, the response may be ineffective if the equipment can not be transported to the site fast enough or if recovery efforts must be terminated due to unsafe conditions.

Countermeasures Technology

Mechanical Recovery

In some Arctic spill situations oil can be removed from the surface of the water by mechanical skimming devices. Many different types of skimmers have been developed, but few of these have been designed specifically to recover oil from Arctic waters. Moreover, although mechanical oil skimming technology continues to advance, little testing has been done under at-sea Arctic conditions. Even the most effective skimmers have limited capacities for recovering oil in stormy and/or ice-covered Arctic waters. Considering the relatively low percentage of spilled oil they may be able to recover in most Arctic spill scenarios, skimmers are seen by some to be a second-order countermeasure technique.

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[30] Sohio Alaska Petroleum Company, *Challenge Island Spill Report* (March 1982).

The effectiveness of skimming devices depends upon a number of different variables. For one, the thickness of the oil layer to be recovered affects cleanup efficiency. Thus, skimmers are usually used in conjunction with booms which prevent the oil from spreading and becoming too thin to recover. In this respect, ice may sometimes be used to advantage. If ice is present, but not extensive enough to limit skimmer deployment, it may serve as a natural barrier to spreading and thinning. The viscosity of the oil is a second important variable. The mechanical recovery of viscous oil, which may quickly form in cold Arctic waters, is a problem requiring specialized equipment. Skimmer performance is also reduced by high sea states, strong currents, and the presence of debris and/or ice. Skimmers for Arctic spills must be easily maintainable, easy to transport to the spill site, and simple to operate. Skimmer designs which may be useful in certain Arctic spill situations include weir, suction, and sorbent surface devices. Each type of device is available in the Arctic.

Weir skimmers. Weir type skimmers depend on gravity to drain oil off the surface of the water. They operate by allowing the oil to fall over a lip suspended at the surface of the water into a sump placed in the slick. The oil is then pumped out of the sump to a storage facility. The main advantages of this type of skimmer are portability and simplicity. They have proven most useful for recovering light oil in calm water. They are not useful in waves because large volumes of water will enter the sump with the oil (a ratio of 10 percent oil recovery to 90 percent water is not atypical). In larger waves, smaller weir skimmers may be swamped. Weir skimmers can be used in calm, open water Arctic spill situations; however, the presence of ice or other debris may clog the weir openings and render the equipment temporarily inoperative.

Suction devices. Suction devices, if mounted on a suitable operating platform and if used with suitably powerful positive displacement pumps, may prove to be useful in some instances. Since low ambient temperatures predominate in the Arctic, spilled oil is likely to become very viscous; water-in-oil emulsions also may be formed. The main advantage of suction skimmers is their ability to vacuum heavier oil. Even suction pumps, however, will have problems recovering semi-solid oil. Other types of skimmers have difficulty efficiently recovering viscous oil because the oil will not readily flow toward the equipment.

Disc skimmers and rope mops. Sorbent surface devices, including rotating disc skimmers and rope mops, seem to hold promise for efficient operation where small amounts of ice are present. The disc type skimmer collects oil on rotating oleophilic discs. The oil is scraped from the discs, transfered to a screw auger at the axis of the discs, and pumped to storage containers. The advantages of this type of skimmer for Arctic use are its ability to pick up viscous oil and to function amidst limited ice, debris, and waves. However, disc skimmers may become quickly overloaded in heavy oil.

Rope mop skimmers use continuously moving, absorbent, polypropylene ropes to sop up oil. This type of device has relatively good potential as a secondary collection system in broken ice conditions. Rope mop skimmers range in size from very small portable units capable of being mounted on ice-strengthened barges or other platforms to large boats specially designed for skimming operations.

The ARCAT. The largest and most important rope mop skimmer currently on hand in the Arctic is the ARCAT, a 65-foot catamaran dedicated

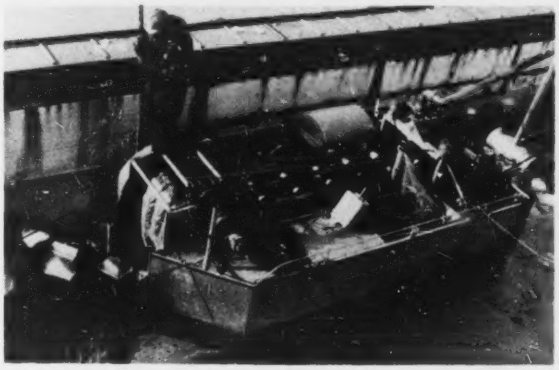

Photo credit: EPA OHMSETT facility

Testing the effectiveness of a rope mop skimmer in cleaning up oil spills in broken ice to spill cleanup in the Beaufort Sea and operated by Alaska Clean Seas. A distance of 6 feet separates the ARCAT's two hulls. However, using diversionary booms and support from two small tow boats, the ARCAT can increase its swath width and thus its oil encounter rate by a factor of 20 or more. By offloading recovered oil into auxiliary oil storage containers, it is hoped that ARCAT will be able to operate continuously for days or even weeks at a time, recovering oil at the average rate of 5 to 30 barrels per hour. Other features of the ARCAT include oil dispersant booms, oil storage capacity, and equipment to break down recovered emulsions.[31]

The maneuverability of the ARCAT has been evaluated in broken ice coverage up to 7 oktas (an okta is equivalent to 12.5 percent—one-eight—coverage). In 2 oktas (25 percent) or less ice coverage, it is able to maneuver through broken ice at speeds of from 5 to 7 knots. In 3 to 5 oktas its speed is reduced to one to 2.5 knots, and, in 6 to 7 oktas to about one-half knot. Industry is satisfied that the ARCAT has been sufficiently tested to demonstrate its utility for recovering oil in broken ice conditions. Industry argues that further testing is not necessary since other skimmers very similar to the ARCAT have been tested with good results in oil, and it is reasonable to conclude that ARCAT mops will behave in the same way. Others are not so sure, since it has not been tested in oil and ice, and believe that the device should be put to the test recovering the type of oil that it will most likely encounter—viscous crude that has weathered for about 3 days in water at 0 °C. Even if ARCAT can handle these tests, special operating procedures may have to be developed. Tests may indicate that different types of mops are necessary, or that it may be necessary to adjust wringer speed, rope speed, or even the vessel speed. These operating procedures could be tested and developed before a spill occurs.

The Force Seven type mop. The Force Seven type rope mop has also been considered in connection with Arctic spill response. This system uses a series of mops deployed from the stern of a vessel. It is attractive because: 1) the area covered can be increased by increasing the number of mops; 2) the device is likely to have some utility in broken ice since the mops are drawn over the surface of the ice; 3) there is no problem of a catamaran hull becoming jammed with ice; and 4) the device can be quickly installed on the stern of any available vessel. This last feature is particularly important. The ARCAT is an expensive vessel, and although it may be used for other purposes, it is dedicated solely to oil spill response. When it isn't recovering oil, it sits unused. As a result, only one ARCAT has been built and deployed to date. If a large spill does occur, however, the use of as many vessels as are available probably will be required if a significant amount of oil is to be recovered. Therefore, availability of equipment that can be mounted on vessels of opportunity probably will be more feasible than dedicated single-purpose vessels.

Few skimmers have been independently tested to evaluate how well they perform in broken ice conditions. In most cases it is simply not known how well they will operate in the different ice conditions which could be encountered. Manufacturers have made optimistic statements about the efficiency of their skimmers for Arctic conditions, but what little independent testing has been done has shown many of these claims to be overstated.

Industry has been using conventional barges and tugs for some time for supporting offshore and nearshore oil spill cleanup operations. One innovation would be an icebreaking barge. Barges provide mobile and stable platforms from which to conduct countermeasures operations. Recent industry demonstrations have shown that rope mop skimmers can be effectively deployed from barges in deteriorating heavy pack ice. The recovery capability of barge-mounted skimmers, however, has not been demonstrated. The oil-encounter rate for these skimmers may not be high; nevertheless, this approach constitutes one more countermeasures tool that may be useful in some situations.

Booms. Booms are used to contain oil. They may either be employed in conjunction with skimming operations (in which case their function is to capture and concentrate oil slicks so that recovery can be as efficient as possible) or for deflecting or excluding oil from particularly sensitive areas. Booms work best in calm water, free of ice or other debris. However, in strong currents (above one knot) and high sea states, the efficiency of containment booms is impaired. In heavy sea states, for instance, oil may either splash over the top of the boom or escape under the skirt. In addition, scattered ice can cause boom damage. In general, booms do not yet seem to have the endurance necessary for continuing performance during a long-term cleanup operation, and booms used in open ocean conditions have not proved to be very effective. In rough environments, the use of booms and skimmers probably would not make a significant difference in the ultimate environmental impact of a spill.

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[31] R. E. Williams, S. J. Bowen, and D. H. Glenn, "Field Trials of the ARCAT II in Prudhoe Bay," Proceedings of the Seventh annual Arctic Marine Oilspill Technical Seminar (Edmonton, Alberta, June 1984).

MMS recommends that booms be able to perform in wave heights of 8 to 10 feet. These performance guidelines have not been met. However, it is still unclear what constitutes adequate boom performance under real conditions, and under high wave conditions, oil will usually be quickly dispersed. Although booms are an indispensable countermeasures tool, their use is clearly limited. A promising addition to containment technology is the high pressure water jet barrier, which currently is being developed. It is used for the same purposes as conventional booms. The water jet system is designed to herd oil in waves, ice, and marsh areas, and can be mounted on and used in conjunction with skimming devices. It has not yet been evaluated in high sea states, however. In addition, the jets create a considerable amount of fine mist. In subfreezing air temperatures, the resulting ice mist could be a health and safety hazard.

Disposal. The ultimate disposal of recovered oil or oiled debris generally takes the form of either landfilling or incinerating the material. Both of these alternatives have drawbacks in a northern application.

The burial or landfilling of oil and oiled debris is possible only if suitable sites are available to construct either subsurface pits or above-grade berms to contain the material. Such sites are not plentiful in the Arctic; where available, they may be difficult to access due to the complete absence of roads and the presence of shallow water at the shore. Ice-rich soils, common in the Arctic, also pose a problem in summer operations since excavation in permafrost can create sloppy, unworkable conditions. Landfilling operations also require the use of heavy equipment which is not plentiful in the North and which would be difficult to transport to specific disposal sites. The major advantage of land filling in the Arctic is the ability to permanently encapsulate the oil and debris in a frozen surrounding.

The state-of-the-art for oil spill disposal by incineration has advanced from earlier attempts at burning oil and debris in oil drums or open pits to a technology including air-transportable incinerators and reciprocating kiln beach cleaners. A transportable flare burner capable of burning 6,000 barrels of light oil per day and 3,000 barrels of heavy oil per day is available in Anchorage. The industry on the North Slope has access to a rental burner that is theoretically capable of incinerating 13,000 barrels of oil per day.[32]

Oiled beach materials such as sand and rock could be cleaned in simple reciprocating kiln devices but such equipment at present has a very low throughput. A larger number of these kilns, along with their manpower and logistical support, would therefore be required to carry out an extensive beach cleaning. It is also apparent that any proposed landfill operation would involve serious logistical problems. This is also the case for any proposed labor-intensive spill control operation in the North, either beach cleaning or debris disposal.

The disposal problem is mainly of concern for large spills. Small spills can be stored until adequate disposal is available. For the Beaufort Sea, the industry points out that it would be technically feasible to transport skimmed oil by barge or possibly over ice to Prudhoe Bay where it could be offloaded into a "slop tank" at one of the flow stations of the Prudhoe Bay Unit. These flow stations have the capability to treat skimmed oil to Trans Alaska Pipeline specifications. Likewise, in the Bering Sea, it may be technically possible to transport skimmed oil in a large oceangoing barge to Kenai, Alaska or Seattle, Washington for deposit into a refinery slop tank.

In Situ Burning

For many Arctic marine oil spills, *in situ* burning is considered to be one of the most practical methods available for removing oil from the environment. This countermeasure method may be used in combination with other techniques to reduce water pollution. The oil that escapes combustion, either as residue or as a partially burned oil layer, might be recovered downstream with skimmers. When burning can be used as an oil spill countermeasure, the problems of disposal encountered with mechanical recovery techniques may be reduced.

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[32] Shell Oil Company, Sohio Alaska Petroleum Company, Exxon Company, and Amoco Production Company, *Oil Spill Response in the Arctic* (Three parts, April 1984).

In situ burning may be practical for both contained and uncontained spills. In an uncontained slick, such as one from a tanker spill in open water, burning may be the only feasible method of significantly reducing the amount of oil in the water. Even if mechanical recovery equipment could be deployed to a remote spill site, it probably could not be expected to remove more than a small fraction of the oil from a large batch spill, and the problem of disposal of recovered oil would remain. Dispersants might be used to counteract some of the adverse effects of uncontained spills, but their effectiveness may be reduced in cold environments.

If spilled oil can be contained, *in situ* burning may be the most efficient removal technique. Oil may be contained naturally or by man-made, fire resistant booms. Winter tanker accidents or winter subsea blowouts are two situations in which spilled oil would be naturally contained and in which *in situ* burning may be successfully used. In either situation, most of the spilled oil would be trapped under the ice for the duration of the winter, and no countermeasures would be possible until breakup begins. Within a very short time, the oil would be encapsulated in the growing ice sheet. If the spill were in the landfast ice zone, the oil would not likely travel very far. However, if the spill were beyond this zone in the moving pack ice, the oil could eventually be spread along a narrow track under the ice for many miles. As the ice begins to decay, the oil would migrate to the surface (where it would emerge in a relatively fresh and unweathered state) and collect in melt pools. Depending upon the size and type of the spill, thousands if not tens of thousands of separate oiled pools could appear. Like spills resulting from open-water tanker accidents, there may be no practical solution other than burning for spills resulting from either winter tanker accidents or winter subsea blowouts.

Photo credit: EPA OHMSETT facility

Testing the effectiveness of *in situ* burning as an oil spill countermeasure

Spills which occur during the broken ice period can also be contained naturally for *in situ* burning, if the ice coverage is adequate (the ice edges tend to limit the spreading tendency of the oil). For some open water or broken ice situations, fire resistant containment booms, although still in the development stage, may provide a way for reducing marine oil pollution.

The major technical issue associated with *in situ* burning is the problem of igniting the oil and keeping it burning. When oil is allowed to spread and thin, it is difficult to burn efficiently. Oil which is thicker than about 2 or 3 millimeters can be ignited and burned. Since oil thins as it spreads, undue delays in ignition result in reduced burn efficiencies. Moderate wind may be helpful if it works to herd the oil against an ice barrier. However, lower burn efficiencies can normally be expected in high wind and low ice concentrations. Weathered oil which has remained in the water is likely to be unburnable because the lighter fractions quickly evaporate, and the remaining oil breaks into windrows. Minimum conditions for burning are currently unknown.

For *in situ* burning of uncontained slicks to be effective, the spreading of the flame must keep up with the spread of the oil itself. The flame spreading velocity is related to the type of oil burned, wind speed, and water temperature. Recent laboratory and test-tank oil burn tests have shown that in most cases the flame spreads as rapidly as the burning oil until the thickness of the leading edge of the slick drops below that necessary to support combustion. Beyond this point, only the thick portions of the slick burn. However, certain ignition patterns, such as igniting the circumference of the slick, may be able to overcome this problem. Combustion efficiencies vary proportionally with spill size, wind speed, amount of ice, water temperature, oil type, ignition delay, and pattern of ignition. Efficiencies of up to 80 percent by volume can be achieved, with lower efficiencies expected, for instance, in high winds and low ice concentrations. If adverse conditions persist, cleanup efficiencies could drop below 20 percent.

The 1983 Alaskan Tier 2 field demonstrations of industry's ability to clean up oil in broken ice included industry demonstrations of *in situ* burning. Task 1 consisted of a series of burns of oil in grounded and floating ice. Although the demonstrations were less successful when the ice was floating rather than grounded, they clearly showed that burning is an important component of Arctic oil spill response and cleanup if the oil enters moving broken ice. In its evaluation of the demonstration, the State of Alaska noted that the relatively high efficiency of *in situ* burning depended on the crucial assumption that burning must take place close to the spill source while the oil layer is relatively thick and easily combustible. In many situations, however, a safe burn near the source of a blowout may be impossible, and therefore the burn efficiency will be significantly reduced. It is suggested that more work on the ignition and *in situ* burning of crude oil among 3 to 5 oktas of moving ice is necessary to determine the limits of this countermeasure approach with respect to oil weathering, thickness, and environmental conditions.

Wellhead ignition. When *in situ* burning and other countermeasures techniques are not feasible, wellhead ignition is another possibility. This technique has been considered for dealing with blowouts from gravel islands. Combustion and skimming techniques employed in the vicinity of an unignited blowout can be dangerous and countermeasures taken far downstream of a blowout may not be very effective. Therefore, well ignition may be the only way that artificial island blowouts can be rapidly and effectively controlled. It has been roughly estimated that if the wellhead is ignited, approximately 95 percent of the oil would be burned immediately and another three percent could be removed by other cleanup processes, regardless of whether the blowout occurred in broken ice, landfast ice or open water.

However, there are some important unanswered questions concerning the feasibility of wellhead ignition as an oil spill countermeasures technique. Oil companies may be reluctant to ignite blowouts and thus destroy their wells unless there is no alternative. When possible, rapid control of the well may be more effective in minimizing pollution than early ignition of the blowout. Wellhead ignition prevents the use of equipment which could otherwise be used to reduce the flow.

If a blowout were to occur, wellhead ignition would probably not be ordered immediately. There would inevitably be some delay as experts evaluated the best course of action to take, during which time oil would continue to flow. It has been suggested that 24 to 48 hours would be required to analyze the blowout situation. If experts determined that the well could be brought under control within a "reasonable" time period, the well would not be purposely ignited, and alternative well control efforts would commence. The decision would depend on the rate of flow, the likely damage to the rig and equipment if the well were purposely ignited, the potential environmental damage with and without well ignition, and the safety, cost, and efficiency of cleanup options.

The State of Alaska's decision to grant year-round exploratory drilling on and inside the barrier islands to qualified lessees (the Tier 2 decision), was based, in part, on the viability of wellhead ignition as a countermeasures option. A major question, however, is whether government authorities (either the Alaska Department of Environmental Conservation or the United States Coast Guard) would be willing to order a blowout ignited, recognizing the possible legal problems which might ensue if industry claimed that the well could have been saved and that other techniques could have been used. If ignition is ordered by these authorities, it is not altogether clear who would pay for the damage to equipment. There is also some concern about the safety of ignition. On offshore structures, for instance, it is possible that igniting a blowout could destroy blowout preventers which might be used to bring the blowout under control. In this situation, the capability to drill a relief well becomes very important. Depending upon the area in question and the availability of rigs, a relief well could take from one to three months to drill. Hence, a buffer period would be required so that relief well drilling could be completed before the fall freezeup. Wellhead ignition should probably not be considered a preferred countermeasure, but rather as a last resort to use in the absence of any better technique.

Air-deployable igniters. Any approach to dealing with spills beneath ice must take into account that the size of the area that might have to be cleaned could be extremely large, that there could be numerous unconnected pools of oil to clean up, and that putting cleanup personnel on the ice surface is potentially unsafe. To overcome these problems, a considerable amount of effort has gone into developing igniters which are inexpensive and safe for use from helicopters. One of the requirements specified by Alaska's Department of Environmental Conservation in order for a lessee to obtain approval of its contingency plan is that the lessee must be able to obtain 500 *in situ* igniters within 6 hours of a spill and an additional 1,000 igniters within 48 hours of a spill. Still, this number of igniters might be inadequate for certain types of spills. It has been estimated, for instance, that up to 30,000 igniters could be needed to ignite the oil from a large spill from a tanker. Research is continuing on developing more efficient igniters, and one of the more promising techniques currently under investigation is that of airborne laser ignition.[33]

Collection and disposal of residue. Although *in situ* burning is considered the most practical countermeasure for oil spills on solid or in broken ice, little attention has been given to collection and disposal of the residue from a burn, which could be as much as 35 percent of the volume of the oil spilled. Such residue will be viscous and difficult to handle. While flare burners could be used to dispose of oil and oil/water mixtures recovered by mechanical devices, residue from *in situ* burning may be too viscous to burn. Field tests have shown that burn residue can be removed using sorbents. However, burn residue and sorbent material must first be collected and then transported to an incineration site, which may not be an easy task if the spill is distant from onshore facilities.

Air pollution. In situ burning in many places in the United States would be considered unacceptable because of the smoke and products of combustion. On the North Slope it may be less objectionable because it is remote from populated areas. Environment Canada conducted a brief study of the characteristics of atmospheric emissions from *in situ* burning in 1979 and concluded that "in the immediate vicinity of the fire, the concentration of particulates (soot) will be undesirably high and such areas should be avoided. The concentrations at distances of 10 to 40 km and beyond are judged to be sufficiently low that no adverse air quality problem exists."[34] The study further notes that polynuclear aromatic hydrocarbons in the oil soot have been established as potent carcinogens and are regarded as being only slowly biodegradable. The toxicity of the amounts of these substances likely to be present in the soot has not yet been established, but the Canadian report recommends that it is prudent to minimize human exposure to these substances. This could probably be accomplished by careful planning of the burning operations, taking into account short range weather forecasts.

More recently, the Alaska Department of Environmental Conservation and the Alaska Department of Natural Resources have noted that it is unlikely, given the remoteness from population centers of Arctic oil and gas activities, that concentrations of the byproducts of *in situ* burning of oil will reach levels in which a hazard to humans and wildlife will be present. They plan to use a dispersion model to analyze the air quality impact before deciding to order a blowout ignited or burn large quantities of oil *in situ*. Despite possible air contamination, it is generally believed that in balance it may be more advantageous to burn the oil rather than allow it to remain in the marine environment.

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[33] I. A. Buist, R. C. Belore, and L. B. Solsberg, "Countermeasures for a Major Oil Spill from a Tanker in Arctic Waters,"Proceedings of the Seventh Annual Arctic Marine Oilspill Technical Seminar (Edmonton, Alberta, June 1984).

[34] Tom Day, et. al., *Characteristics of Atmospheric Emmissions from an In-Situ Crude Oil Fire* (Ottawa: Environment Canada, October 1979), p. 58.

Finally, although it will be possible to burn oil that surfaces in melt pools in the spring, if large quantities of oil are involved, it may be desirable to take action sooner. The Alaskan Beaufort Sea Oilspill Response Body (ABSORB) has sponsored research investigating the possibility of drilling through the ice to reach oil pooled beneath. Since oil from a winter subsea blowout would be trapped in cavities under the ice, it may be possible to put personnel and heavy equipment on the ice in winter to drill down to oil trapped in the larger pools—if it can be located—and pump it out. This approach would not require developing any new equipment.

Dispersants

Dispersants are chemical agents used to eliminate oil from the surface of the water and distribute it though the upper few meters of the water column. Used on an oil slick, dispersants decrease the interfacial tension between oil and water, thus reducing the cohesiveness of the slick and promoting the formation of small droplets, which, with the aid of wind and waves, move downward into the water column. Natural degradation by oil consuming bacteria and other processes eventually takes place. The use of dispersants as an oil spill countermeasure may be appropriate if: 1) sea conditions are too rough for deployment and/or efficient operation of collection and recovery equipment; 2) the spill is too large; 3) the spill site is too remote for efficient mechanical recovery or *in situ* burning; 4) it is necessary to stop the movement of a slick toward shore; 5) the oil slick presents a fire hazard; or 6) the probability of contaminating wildfowl is high.[35]

There are several problems associated with the use of dispersants. For one, dispersants may adversely affect marine organisms. The first dispersants used for oil spills were hydrocarbon-base solvents. In response to the Torrey Canyon spill it was found that, when applied in large doses, these first-generation dispersants were lethal to marine organisms. Dispersants thus acquired the reputation of being compounds too harmful to marine life to be used as an oil spill countermeasure. More recently, "third-generation" dispersants have been developed. For these dispersants, the water on which the oil is floating serves as the reactant in the dispersing process. This eliminates the need for hydrocarbon solvents, and greatly reduces the biological toxicity. The most effective dispersants are those which maximize dispersal of oil at sea but have a minimal impact on key organisms living in the water column and sediments. Although the most recent generation of dispersants are relatively nontoxic, there may still be problems associated with placing dissolved and particulate oil in the water column. It is believed that sub-lethal effects (e.g., tainting of marine species) are the main biological concern.

The decision to use or not to use chemical dispersants relates to the expected severity of oil spill impacts on wildfowl, beaches, or wildlife. The safe use of dispersants requires an understanding of the fate, behavior, and effects of treated and untreated oil spills. Since the potential exists for improper use, dispersants must be thoroughly tested before being placed on the EPA approved list.

A second problem concerns the effectiveness of dispersants in cold climates. Dispersants formulated for use in temperate regions may not be well-suited for use in the Arctic, since cold temperatures increase the oil's viscosity, thereby reducing the ability of the dispersant to break down the slick. Since dispersants require relatively high surface mixing, their use would probably not be effective in broken ice conditions. Currently available dispersants are less effective in acting on water-in-oil emulsions. Another temperature-related problem is the potential for the dispersant to separate, freeze, or gel at low temperatures which might cause problems in spraying. Also, the amount of mixing, the degree of weathering of the oil, the dispersant-to-oil ratio, uniformity of coverage, the size of the oil droplets (they must be small enough to create a permanent dispersion), the presence of slush ice, and the degree of salinity affect dispersion. For instance, dispersants require mixing to be effective, and sufficient wave energy is often not present off the North Slope. In addition, since current oil and gas operations in the Alaskan Beaufort Sea are in very shallow water, the use of dispersants may not be an effective way to degrade the oil and may not be desirable from an environmental point of view.

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[35] American Petroleum Institute, *Oil Spill Cleanup: A Primer* (Washington, DC, 1982).

On the other hand, dispersants could be effective in the Navarin Basin, where there is more wave energy and deeper water, and where marine life and wildfowl are more dispersed.

Dispersants have been developed in the last few years which apparently require little mixing *in addition to* normal wave action, and this development has stimulated research and development in aerial application techniques. Dispersant effectiveness, toxicity, and logistics support requirements probably should be examined in light of the much greater slick thicknesses associated with fresh oil films in the Arctic. Ultimately, it could be possible to rank dispersants according to their effectiveness in specific types of situations.

The effectiveness of dispersants as a countermeasure in Arctic waters has yet to be adequately demonstrated under cold marine conditions. Questions remain, for instance, about whether aerially applied dispersants work the way they are supposed to or merely 'herd' the oil to either side of the spray path. The two largest dispersant manufacturers, British Petroleum and Exxon, are actively involved in developing chemical dispersants that will be more effective in treating Arctic oil spills, or other viscous spills.

Logistics problems and high costs of using dispersants as a countermeasure for large, remote Arctic spills may ultimately prove to be the factors most limiting their use. Since dispersants must be applied from either ships or aircraft, their use depends upon the availability of expensive equipment. Moreover, for major spills, large quantities of dispersants will be required. Long distances require large amounts of fuel. However, aerial dispersant operations could be carried out in all Alaska OCS areas from existing aircraft landing facilities.

For use in remote Arctic locations (e.g., to apply to oil from a tanker spill), aircraft may be the only practical means of delivery, because for dispersants to be effective, they must be applied as soon as possible after a spill. It has been estimated that a response effort for remote spills could require three to four days to mount. By this time, however, the increased viscosity of the oil would make currently available dispersants much less effective. Thus, until more effective dispersants are developed, aerial applications will not likely be a useful countermeasures technique for remote tanker spills. Moreover, expensive stockpiling of sufficient quantities of dispersants at strategic locations and a well-rehearsed logistics plan for delivering the chemical to the spill site probably will be crucial if future applications are to be successful. More promising, perhaps, is the use of dispersants to combat oil from blowouts which is thin and fresh, and for fresh spills in choppy seas which can be reached quickly. Other applications might include small batch spills and protection of nearshore areas.

Shoreline Cleanup

Conventional shoreline cleanup in the south involves the containment of oil at shore, the removal of oil and oiled debris by manual and mechanized means, and the cleaning of rocks and man-made structures by high-pressure water and steam. Northern cleanup and restoration operations will utilize techniques and equipment much as in the south. The northern shoreline cleanup operation will, however, likely be complicated by several factors.

Outside the Prudhoe Bay area, a large work force is not available in the Arctic. Since many cleanup steps require manual labor, responses to northern spills may face labor shortages. Heavy equipment will have to be used sparingly due to the sensitive nature of the northern shorelines and their slow recuperative abilities. In many instances, beach material will not support heavy loads. In addition, the presence of boulders and other irregular features on the surface preclude the use of any large mechanized vehicle. The lack of road access in the Arctic means personnel and equipment will have to be transported to the spill site by water or air. Cold temperatures much of the year and periods of prolonged darkness will also complicate northern shoreline cleanup operations. While all of the southern shoreline cleanup techniques are generally applicable to the Arctic study area, the remote nature and harsh but fragile environment of the North will make their application more difficult and less efficient. In most cases, beaches and shorelines will likely be left to regenerate by natural means.

Conversely, shoreline response may not be as time sensitive as offshore or nearshore cleanup; thus, there would be more time to import additional labor from Fairbanks, Anchorage, or elsewhere. In the northernmost areas, the shoreline would be in a frozen or semi-frozen condition most of the year, which would limit the amount of oil that would penetrate the surface. Industry expects that most shoreline cleanup operations would take place during the summer when there is much more daylight than in the lower latitudes.

Monitoring and Surveillance

The effectiveness of many control operations depends on the ability to monitor the position, direction of drift, and size of oil slicks. The vast areas and remoteness of the Arctic, as well as long periods of darkness, complicate this task. The most obvious method of tracking the oil is by visual observation from aircraft. In many cases this will not be possible in the Arctic because of prolonged periods of poor visibility due to either weather or seasonal daylight conditions. Many other methods have been developed for this purpose which will improve surveillance under northern conditions.

Radio tracking buoys monitored from land, ships or aircraft have been constructed to simulate the behavior of specific oil types. Tracking distances of 15 kilometers from the water and 45 kilometers from the air for periods of up to three weeks are possible with the present equipment.

The use of both passive and active airborne remote-sensing packages for tracking and locating purposes has been advanced in recent years. Pictures of spill extent and location can be made through color or filtered black and white photographs. Low-light television systems can differentiate oil slicks from wind and wave patterns but are ineffective in the dark and are unable to discriminate oil from foam, slush ice or brash ice. A day or night system—the laser fluorosensor—is able to detect oil on water, on ice, and in ice-infested conditions. It is limited to the detection of oil at, or very near the surface of the water or ice. Dual, infrared/ultraviolet, line scanners have been successful in locating oil on a real-time basis during the day. Side Looking Airborne Radar (SLAR) is able to cover a larger area in one pass from an airplane or satellite. These SLAR systems are effective, day or night, in detecting oil only in ice-free waters. None of the sensors currently available have been proven to detect oil in broken ice, with the exception of the laser fluorsensor, which is still being tested.

Satellite imagery is another means of locating and tracking oil slicks during daylight hours. Currently, the LANDSAT series of satellites scan the Arctic with sensors in the red, green, and near infrared. This information can be used to identify the position and extent of an oil slick. Plans to mount improved sensors in these orbiting stations will undoubtedly enhance the use of satellites for future monitoring.

Government/Industry Responsibilities

Primary responsibility to clean up oil spills rests with industry, and, although industry has treated the oil spill issue seriously, it has developed only limited capability to contain or clean up a spill in the Arctic. It is the responsibility of Federal and State governments to ensure that industry is adequately prepared to respond to oil spills and to provide backup assistance when necessary.

Federal Government

Since the Santa Barbara blowout, improvements in the regulations governing OCS oil and gas exploration and development have been made by the Department of the Interior. New regulations regarding subsea blowout preventers, worker training programs, oil spill contingency plans, and inspections have been implemented since 1970. In addition, several laws establish penalties for spilling oil and assess liability for polluters. For example, amendments to the FWPCA in 1972, 1977, and 1978 have increased civil and criminal penalties that may be incurred for polluting. Polluters may now be fined up to $10,000 for failure to report an incident, and up to $50,000 for each offense (and more if willful misconduct or negligence can be proved). Under the FWPCA, vessel owners are liable for cleanup costs of up to $150 per gross ton and owners of offshore facilities may be liable for cleanup costs up to $50 million. The Administration supported recent congressional attempts to further increase pollution penalties and liability limits.

Federal responsibilities in the event of offshore oil spills are specified in the National Oil and Hazardous Substances Pollution Contingency Plan, developed in response to the FWPCA. The plan designates the Coast Guard and the MMS as the lead government agencies with responsibilities for offshore oil spill mitigation and cleanup. The respective responsibilities of these two agencies have been clarified in several memoranda of understanding.

In general, the Coast Guard is responsible for coordinating and directing measures to contain and remove pollutants from the water, while the MMS is responsible for coordinating and directing measures to abate the source of the pollution. In the Alaska coastal region, responsibilities are further delineated by the Alaska Coastal Region Multi-Agency Oil and Hazardous Substances Pollution Contingency Plan. Although the primary responsibility for pollution response lies with the Coast Guard, the MMS does have the authority to suspend response operations within a 500-meter radius of the pollution source to facilitate abatement measures.

Supervising and monitoring is the Coast Guard's normal role in managing a cleanup operation. It is Coast Guard policy to encourage the responsible operator to undertake proper removal actions. However, the Coast Guard is prepared to direct the response if the responsible operator is either unknown or not taking satisfactory action. When the Coast Guard is simply monitoring the cleanup operation, removal is done by commercial cleanup contractors and industry cooperatives. Historically, the Coast Guard has been directly involved in only one out of five removal operations. When this happens, the Coast Guard uses its pollution revolving fund ($35 million, established by the FWPCA).[36]

In the event of an offshore spill, the Coast Guard provides an On-Scene Coordinator (OSC) (the Captain of the Port within a specific area of the coastal zone). The OSC coordinates or directs the Federal response to actual or potential pollution incidents. If the OSC decides that cleanup is inadequate or cannot find anyone to immediately assume responsibility for directing an action which is considered necessary, he or she will declare a Federal response and take over actual management of the cleanup. Commercial contractors are used whenever possible, since it is the Coast Guard's policy not to compete with private industry. However, the Coast Guard has developed a modest inventory of equipment for use where commercial sources are either not available or do not have the necessary amount or type of equipment. Much of the Coast Guard's equipment is for use to combat open water spills and was designed specifically for its use, since there are fewer commercial sources for this type of equipment.

The OSC has a number of resources available to expand the amount of equipment, personnel, and expertise available. The Regional Response Team (RRT) can be convened at the request of the OSC for advice or assistance in obtaining equipment or other support. The RRT is also responsible for planning and preparedness prior to spills. The team consists of regional representatives of the Departments of Agriculture, Commerce (NOAA), Defense, Energy, Health and Human Services, Interior, Justice, Labor, State, and Transportation, EPA, the Federal Emergency Management Agency, and representatives of State governments. The National Response Team (NRT), composed of Federal agency representatives at the national level, is also available to assist the OSC. The NRT is consulted for major policy decisions or when large scale or specialized support not available to the RRT is needed.

The National Strike Force (NSF) is a key Coast Guard resource available to the OSC. When commercial resources are not adequate, the NSF is employed. The Strike Force consists of several teams specially trained and equipped to respond to oil spills. The Pacific Strike Team of the NSF, located in Marin County, California, is the unit charged with responding to spills in the Arctic. The NSF maintains a stock of specialized equipment that can be deployed anywhere in nation. It is also involved in testing and evaluation of equipment and response methods. Other resources upon which the OSC can draw are the Scientific Support Coordinator provided by NOAA, EPA, State and local governments, and the academic community.

The Coast Guard has developed regional and local contingency plans in preparation for spills. These plans include data on possible pollution sources, location of environmentally sensitive areas, available contractors/cooperatives and their equipment, and plans for protecting vulnerable resources within the area. An Environmental Atlas for the Alaskan Beaufort Sea, which contains information concerning general oceanography, meteorology, ice, and climatology recently has been compiled for use by the OSC. By compiling available information on environmental conditions and variables, the OSC is better able to understand the environmental conditions one could expect to encounter in the event of a spill. If the atlas proves useful, the Coast Guard plans to develop atlases for other lease sale areas of the Alaskan OCS.

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[36] *Coast Guard Capabilities for Oilspill Cleanup*, Hearing before the House Committee on Government Operations (August 26, 1982).

Industry

The offshore oil and gas industry must comply with OCS regulations and orders. Regulations are general rules applicable to OCS operations everywhere. OCS orders are published by the MMS and refer to particular areas. These orders expand upon the regulations and provide more detailed guidance on regulatory requirements. OCS Order No. 7 stipulates the pollution prevention and control measures required of industry. This order specifies that lessees shall submit a description of procedures, personnel, and equipment to be used in reporting, cleaning up, and preventing oil spills which may occur during exploration or development activities. The order also requires lessees to maintain (or to have readily available) pollution control equipment, including booms, skimmers, cleanup materials, and chemical agents. In addition, requirements for drills and training procedures are also stipulated.

In addition to other requirements, OCS Order No. 7 requires that all companies that propose to do work in the Arctic submit an oil spill contingency plan. Contingency plans are reviewed annually and must contain information concerning: 1) amount, type, and location of all countermeasures equipment and time required for its deployment; 2) alternative responses for spills of varying severity; 3) plans for protection of areas of special biological sensitivity; 4) procedures for early detection and timely notification of an oil spill, including names and telephone numbers of people to notify; and 5) the necessary steps to be taken to assess the seriousness of the spill, plan the response, and begin cleanup actions. Oil companies must specify an oil spill response operating team consisting of trained, prepared, and available operating personnel; an oil spill response coordinator; a response operations center and reliable communications system for coordinating the response; and provisions for disposal of recovered spill materials.

The Coast Guard reviews and advises the MMS as to the adequacy of industry oil spill contingency plans submitted to MMS. Criteria for evaluating plans have been defined jointly by the two agencies. The Coast Guard and MMS consider: 1) the adequacy of the risk analysis; 2) the adequacy of recovery equipment; 3) equipment availability; 4) the estimated response time; 5) provisions for periodic practice drills; 6) adequacy of support vessels; 7) dispersant equipment; 8) decision procedure for ordering ignition of an uncontrollable well; 9) disposal methods and sites; and 10) detection and monitoring provisions.

Oil spill contingency planning efforts of individual companies are supplemented by a statewide cooperative organization, Alaska Clean Seas (ACS). ACS has been organized to assist member companies in dealing with the possibility of a major spill. ACS maintains spill response equipment and supplies, provides staff assistance for contingency planning and training, and conducts research and development projects to advance the state of the art of oil spill containment and cleanup. ACS is divided into five cost-participation areas: the Beaufort Sea, Norton Sound, St. George Basin, the Gulf of Alaska, and the Navarin Basin. In all, sixteen companies have joined ACS, although memberships of each area vary according to company interests.

ABSORB, the Alaskan Beaufort Sea Oilspill Response Body, is under the ACS umbrella, and is the regional response organization for the Beaufort Sea. Equipment for use by members has been stockpiled at ABSORB's main warehouse in Prudhoe Bay. As far as equipment staging is concerned, industry preparations seem to be very good. In addition to providing supplemental equipment and expertise, ABSORB has studied the biology and shoreline characteristics of the Beaufort Sea, and has recently assembled an oil spill response considerations manual which synthesizes knowledge of the biological resources of the area. Industry points out, with some pride, that it has not yet been necessary to use ABSORB equipment. However, since there have not been any spill incidents, the capability of personnel to respond to spills under realistic conditions, remains unknown. Moreover, for large Arctic spills, it is likely that contractors from outside the region would have to be used. The Cook Inlet Response Organization could possibly also provide support for spills in the Arctic.

The Alaska Cooperative Oilspill Response Planning Committee functions in addition to the industry cooperative organizations. It consists of both industry (ACS) and government (State and Federal) representatives. Its purpose is to foster sharing of resources and technical expertise and to facilitate cooperative oil spill response.

State of Alaska

The Alaskan Department of Environmental Conservation requires that an oil spill contingency plan be approved (and renewed at least once every three years) for operations within State waters. Moreover, concurrence of the State in the adequacy of oil spill contingency plans must be obtained to the extent required the CZMA. Like the Coast Guard, if the State determines that containment and cleanup activities are not adequate, the department may undertake cleanup itself and/or may issue a contract for the cleanup. Where the Coast Guard has primary authority, the State may still authorize supplemental cleanup or containment efforts.

State contingency plans are similar in most respects to Federal requirements. Of special note, for Tier 2 approval the State requires that 500 in situ igniters be available within 6 hours of a spill, and that an additional 1,000 be obtainable within 48 hours of spill. The state also requires that 1,000 feet of fire resistent boom be stored on site, and that an additional 2,500 feet be available within six hours. In addition, plans must be submitted for drilling a relief well, and the decision process necessary to ignite a well must be outlined.[37]

Technology Development

Under the OCS Lands Act, the Federal government requires that the oil industry use the best available and safest technologies (BAST) in their drilling and production operations. Criteria exist for evaluating the adequacy of most equipment or processes, but there are as yet no standards for evaluating offshore oil spill cleanup technology. One problem is that it is difficult to determine what proportion of spilled oil is "adequate" to clean up or how much can reasonably be expected to be cleaned up in spill situations. The definition of "adequacy" is as much a political issue as a technological one. Neither the government nor the oil and gas industry is currently required to demonstrate which oil spill technology is best.

Three Federal agencies have small inhouse oil spill research and development programs: the MMS, the Coast Guard, and EPA. Total Federal funding for oil spill technology research has averaged less than $1 million per year over the past five years. One million dollars per year is considered small in view of: a) the unknown and/or inadequate capabilities of oil spill containment and cleanup technologies for frontier areas; b) the Administration's objective of accelerating OCS development; and c) the fact that the total economic costs of major spills may reach several hundred million dollars. Suggestions of the kinds of oil spill technology research needed are given in table 7-3.

Representatives from the U.S. agencies, along with the U.S. Navy and the Environmental Protection Service (EPS) of Canada, comprise the OHMSETT (Oil and Hazardous Materials Simulated Environmental Test Tank) Interagency Technical Committee (OITC). Although the Coast Guard has funded some Arctic and offshore spill technology research since the early 1970s, the OITC did not become involved in Arctic or offshore oil spill technology research until 1984. The objective of the OITC program is to evaluate oil spill countermeasures equipment and methods for OCS conditions. The OHMSETT test tank, located in Leonardo, New Jersey, has been used to evaluate Arctic oil spill technology. However, because this program is new and because there have

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[37] Alaska Departments of Environmental Conservation and Natural Resources, "Final Finding and Decision of the Commissioners Regarding the Oil Industry's Capability to Clean Up Spilled Oil During Broken Ice Periods in the Alaskan Beaufort Sea" (June 1984).

Table 7-3.—Oil Spill Technology Research Needs

Assessment of capabilities of existing oil spill equipment and techniques under realistic conditions
Field or large-scale tank tests of behavior of North Slope crude oil in cold water and in ice
Assessment of behavior of oil in a moving, broken ice field
Development of a portable oil spill response system to be used on tankers
Development of a containment boom that can be used in broken ice conditions
Development of better techniques for oil spill cleanup in shallow, nearshore waters
Development of better techniques for containing oil in scattered ice floes outside the protection of the barrier islands
Development of more effective igniters
Development of an oil spill recovery system that can be used on vessels-of-opportunity (vessels used to supply offshore operations)
Determine and record the properties of air and water-borne residues of in situ burning
Determine minimum boundary conditions for effective in situ burning (thickness, degree of weathering, containment requirements)
Refine fire resistant containment booms
Review dispersants for cold and open water applications

SOURCE: Office of Technology Assessment.

been funding limitations, little testing of equipment for use in Arctic or deepwater areas has been accomplished to date.

The OITC has recently proposed a 5-year program for testing OCS booms and skimmers. This program would consist of three phases: 1) tank testing; 2) assessment of equipment capability at sea for seakeeping and durability (in accordance with a rigorous, pre-determined test protocol); and 3) exposure of the equipment under OCS conditions to intentional oil spills. The OITC also proposes to continue tests, begun in 1984, on the potential for mechanical recovery and *in situ* burning of oil in broken ice as a mitigation measure; to continue investigation of new technologies; and to take advantage, when possible, of spills-of-opportunity to gather equipment performance data.

The OITC program has been level-funded at $400,000 per year with the MMS, Coast Guard, and EPA each contributing about $125,000, and EPS contributing about $25,000. Continued funding at this level is considered unlikely in light of the budget constraints of the participating agencies. EPS participation is considered very important, since the Canadian agency also conducts spill research, the results of which are available to the OITC. The Coast Guard also contributes logistical support. Although the MMS has spent about $372 million (or an average of approximately $31 million per year) for OCS environmental studies since 1973, none of this money has been allocated for oil spill equipment research.

Since the 1970s, little industry or government effort has been given to developing technology or methods for the specific purpose of combatting oil spills in deepwater. As oil and gas activities increase in deeper and more distant waters, the continued use of conventional recovery equipment in these areas may need further analysis. In particular, technologies for open-ocean rough sea recovery and deepwater sea floor containment may need further development. However, the major difference between countermeasures problems in deepwater and spill problems nearshore is logistical rather than technological. Logistical concerns include how to transport the equipment needed to contain, recover, store, and dispose of oil to the spill site in a timely way.

The MMS is currently funding two engineering studies to deal specifically with deepwater subsea blowouts: 1) the feasibility of deploying a large self-contained collection ship capable of remaining on-station while collecting oil and gas from a blowing well using a subsea collector similar to that used in the Ixtoc 1 blowout (the "sombrero"); and 2) the feasibility of deploying a collection ship equipped with skimming booms to collect and separate oil in close proximity to a blowing well. Such a ship would have to be large enough to remain on-station in heavy weather and to store two to three weeks of recovered oil. The availability of such self-contained ships could possibly overcome many of the logistics problems related to deepwater spills; however, costs may be extremely high.

Appendixes

Appendix A

Offshore Leasing Systems

U.S. Federal Leasing System for Offshore Areas

Description

Federal offshore leasing is conducted according to the guidelines contained in the Outer Continental Shelf (OCS) Lands Act of 1953, as amended in 1978, which authorizes the Secretary of the Interior to grant mineral leases for OCS lands and to prescribe any necessary regulations. Currently, the Minerals Management Service (MMS) within the Department of the Interior is responsible for implementing the offshore leasing system and the operating regulations.

In general, the Interior Department identifies an area for leasing in accordance with a pre-set lease schedule. It surveys the hydrocarbon potential, calls for information, and prepares a draft environmental impact statement. After filing a final environmental impact statement with the Environmental Protection Agency, the lease sale is announced and comments are solicited from the States and other interested parties. With appropriate modifications, the lease sale takes place and firms are awarded offshore tracts according to a competitive bidding process. In the post-lease phase, companies must submit extensive safety and environmental protection plans with each stage of exploration, development, and production. The post-lease management functions of the Department of the Interior involve approval and enforcement of the plans and collection of government revenues. The pre-lease and post-lease steps of the leasing process are outlined in table A-1 and figure A-1.

LEASE SCHEDULE

Prior to the enactment of the OCS Lands Act Amendments of 1978, the Department of the Interior was not required to develop a prospective leasing program or plan. Between the start of leasing in 1954 and 1967, nearly all offshore tracts nominated by the industry were offered for leasing. However, in 1967, the Department of the Interior instituted a formal nomination and selection system that required a resource evaluation and determination of industry interest before tracts were offered for sale. Subsequent to the passage of the OCS Lands Act Amendments of 1978, leasing programs have been developed in accordance with Section 18 of the Act, which requires that the Secretary of the Interior prepare and periodically review a 5-year leasing schedule which is consistent with the principles of the Act.

The selection of areas to be included in the lease schedule is influenced by initial assessments of oil and gas potential, environmental concerns, economic conditions, location of commercial fisheries, availability of technology, and other factors. Geological and environmental information on the Outer Continental Shelf is collected and evaluated by the Department of the Interior. Companies may obtain permits for preliminary offshore exploratory activity, including broad area reconnaissance to identify promising geologic formations and requirements for more detailed seismic surveys. In certain circumstances, permits may be granted to firms to take bottom samples or cores (COST wells) to obtain additional geologic information. The government may request the submission of all pre-lease geological and geophysical data and information.

Final approval of the 5-year OCS leasing program takes approximately 2 years. Comments are solicited from the States, industry, Federal agencies, and other interested parties at several points in the development of the plan. After comments are received and appropriate modifications are made, the final schedule is submitted to the President and Congress for review.

CALL FOR INFORMATION

The initiation of individual lease sales begins with the identification of areas of hydrocarbon potential by the Department of the Interior. A Call for Information is issued for a large area, usually consisting of several million acres, and is published in the *Federal Register* with a 45-day comment period. Potential bidders are asked to identify areas they wish to have offered for lease. States and other interested parties may identify and recommend areas which should be excluded from oil and gas leasing or only leased under special conditions because of conflicting resource values or environmental concerns. At the same time, a Notice of Intent to prepare an Environmental Impact Statement (EIS) is published, which invites public assistance in determining significant issues. The information received from the public, as well as the resource, environmental, and technical information collected by the Department of the Interior, are used to identify an area for further analysis in the EIS.

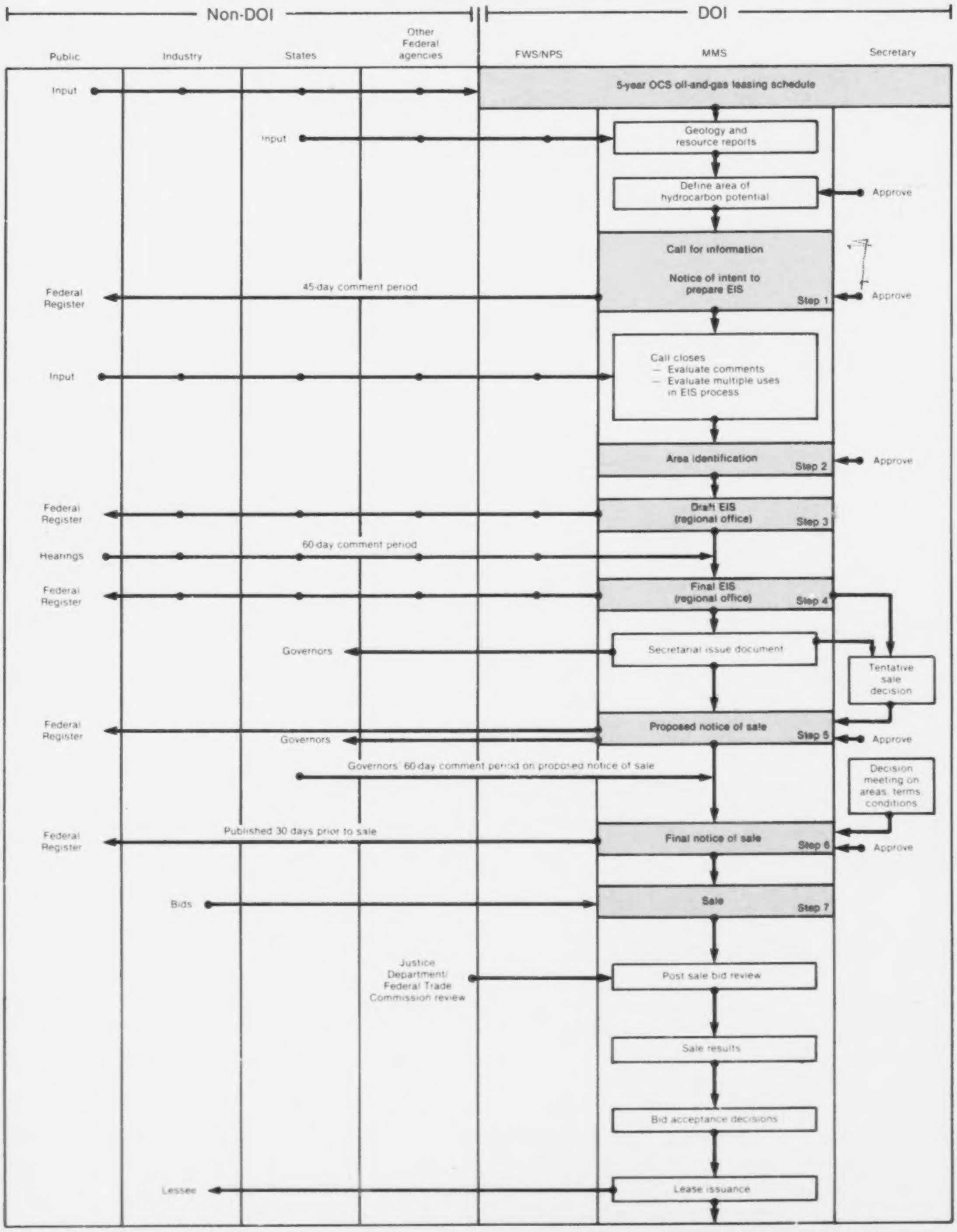
In the proposed 1986-91 5-year leasing schedule, an additional lease sale step has been added for selected frontier-area sales. A Request for Interest will be made four months prior to the Call for Information. This request will help determine industry interest in leasing in these areas and whether the 2-year sale process should

Table A-1.—Steps in Offshore Leasing (1984)

Activity	Timeframe: month Lower 48	 Alaska	Action
Pre-lease phase:			
Five-Year Leasing Program	2-5 years prior to to call		Prepare schedule of proposed lease sales, to be revised annually. Industry, states, and other parties comment prior to final approval.
Identify area of Hydrocarbon Potential	At least 2 months prior to call		Identify area of hydrocarbon potential (AHP) for upcoming sale.
Call for Information; Publish Notice of Intent to Prepare EIS	1	1	Request bidders to indicate areas of interest and solicit comments from all interested parties. Due in 45 days. Also announce initiation of EIS scoping.
Area Indentification	4	4	Identify areas for detailed environment analysis.
Draft Environmental Impact Statement	12	15	Draft EIS issued for planning area and notice published in Federal Register. Comments requested and hearings held during 60-day comment period.
Final Environmental Impact Statement	18	21	Revised EIS submitted to EPA for review and made available to public.
Proposed Notice of Lease Sale	19	22	Proposed notice of sale, with terms and conditions, sent to States for comment for a 60-day period.
Final Notice of Lease Sale	22	25	Final notice of sale published in Federal Register at least 30 days prior to sale.
Lease Sale	23	26	Regional office holds public opening and reading of sealed bids.
Leases Issued	25	28	Leases issued not later than 90 days later, after bid review and anti-trust review.
Post-lease phase:			
Exploration Plan	Within 4 years of lease issue (for 5-year terms)		Lessee submits exploration plan and environmental report. States evaluate for CZM consistency.
Environmental Analysis			MMS conducts environmental analysis, prepares EIS if necessary, and approves or rejects plan.
Exploration Drilling	For all exploration wells		Lessee submits application to drill (APD) and applies for permits from other agencies. After analysis, MMS approves or rejects.
Development and Production Plan	Within 5 years of lease issue/or receives SOP		Lessee submits development and production plan and environmental report. States review for CZM consistency.
Environmental Analysis			MMS conducts environmental analysis, prepares EIS if necessary, and approves or rejects plan.
Development Drilling	For all exploration wells		Lessee submits APD and required permits, State CZM ruling, and platform verification and certification. MMS approves or rejects.
Pipeline Permits			Lessee applies for pipeline permits from MMS and other relevant agencies.
Production	For duation of production		Lessee submits monthly production reports and royalty payments.
Relinquishment	Cancellation or shutdown		Wellheads plugged and equipment removed.

SOURCE: Office of Technology Assessment.

Figure A-1.—Offshore Leasing Process: Pre-Lease


Non-DOI
DOI
Public
Industry
States
Other Federal agencies
FWS/NPS
MMS
Secretary
Input
5-year OCS oil-and-gas leasing schedule
Input
Geology and resource reports
Define area of hydrocarbon potential
Approve
Call for information
Notice of intent to prepare EIS
Step 1
Approve
Federal Register
45-day comment period
Input
Call closes
— Evaluate comments
— Evaluate multiple uses in EIS process
Area identification
Step 2
Approve
Federal Register
Draft EIS (regional office)
Step 3
Hearings
60-day comment period
Federal Register
Final EIS (regional office)
Step 4
Governors
Secretarial issue document
Tentative sale decision
Federal Register
Governors
Proposed notice of sale
Step 5
Approve
Governors' 60-day comment period on proposed notice of sale
Decision meeting on areas, terms, conditions
Federal Register
Published 30 days prior to sale
Final notice of sale
Step 6
Approve
Bids
Sale
Step 7
Justice Department/ Federal Trade Commission review
Post sale bid review
Sale results
Bid acceptance decisions
Lessee
Lease issuance

SOURCE: Minerals Management Service.

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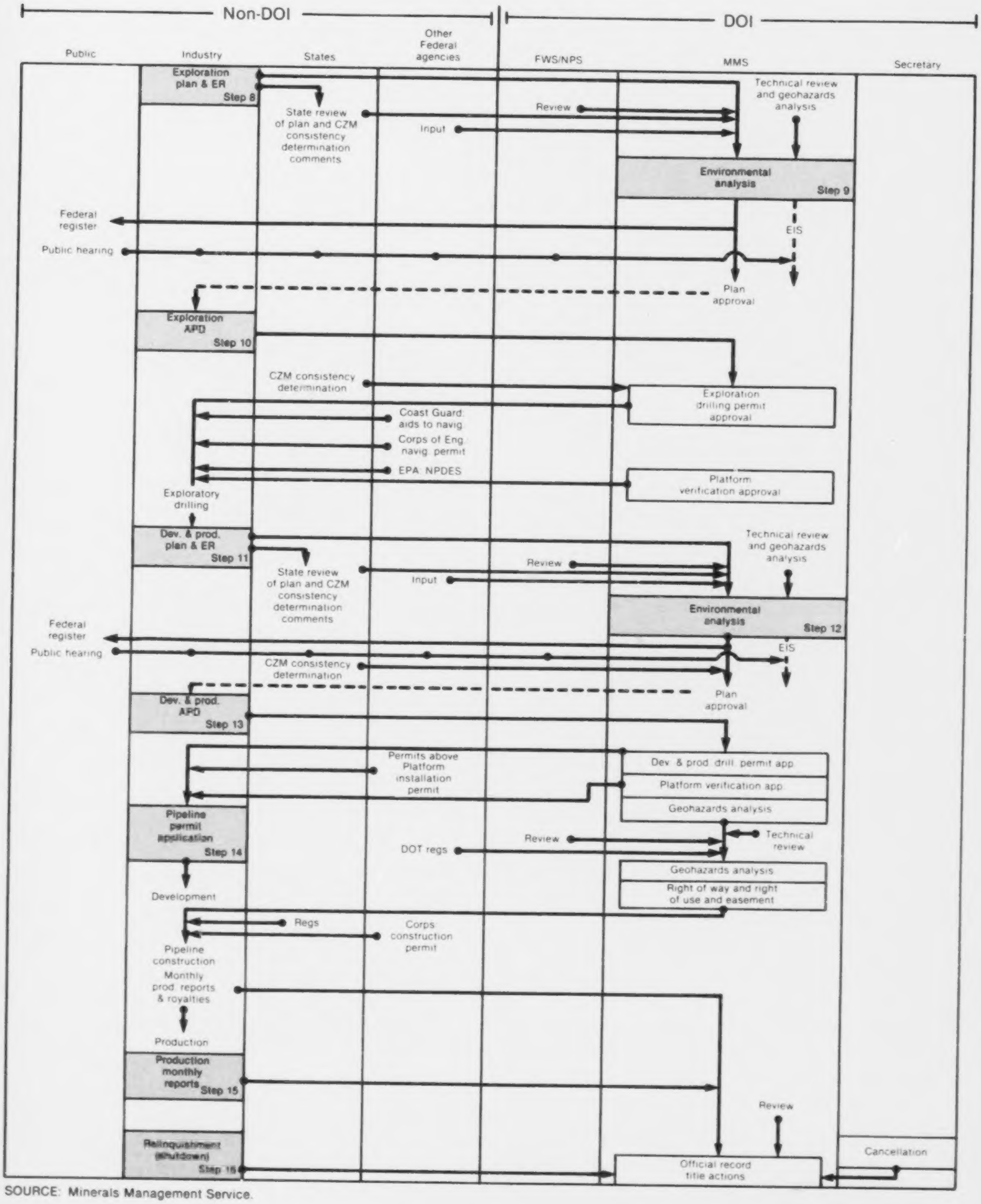
—Offshore Leasing Process: Post-Lease


Non-DOI
DOI
Public
Industry
States
Other Federal agencies
FWS/NPS
MMS
Secretary
Exploration plan & ER Step 8
State review of plan and CZM consistency determination comments
Review
Input
Technical review and geohazards analysis
Environmental analysis Step 9
Federal register
Public hearing
EIS
Plan approval
Exploration APD Step 10
CZM consistency determination
Exploration drilling permit approval
Coast Guard: aids to navig.
Corps of Eng. navig. permit
EPA: NPDES
Platform verification approval
Exploratory drilling
Dev. & prod. plan & ER Step 11
State review of plan and CZM consistency determination comments
Review
Input
Technical review and geohazards analysis
Environmental analysis Step 12
Federal register
Public hearing
CZM consistency determination
EIS
Plan approval
Dev. & prod. APD Step 13
Permits above Platform installation permit
Dev. & prod. drill. permit app.
Platform verification app.
Geohazards analysis
Pipeline permit application Step 14
Review
DOT regs
Technical review
Geohazards analysis
Right of way and right of use and easement
Development
Regs
Corps construction permit
Pipeline construction
Monthly prod. reports & royalties
Production
Production monthly reports Step 15
Review
Relinquishment (shutdown) Step 16
Official record title actions
Cancellation

SOURCE: Minerals Management Service.

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proceed. The Request for Interest will be made for the following Alaska sales: Gulf of Alaska (1988); Cook Inlet (1990); Shumagin (1990); Hope Basin (1991); and Kodiak (1991).

ENVIRONMENTAL ASSESSMENT

The National Environmental Policy Act (NEPA) of 1969 requires the analysis, assessment, and disclosure of environmental impacts that may result from Federal offshore leasing. The environmental assessment process for offshore lease sales involves the preparation of preliminary and final environmental impact statements, public hearings, and consultation with affected States and all interested parties.

The first step is the preparation of a Draft Environmental Impact Statement (DEIS) by the Department of the Interior. For the first sale in a planning area, the DEIS is prepared for the entire area; abbreviated statements are prepared for subsequent sales. The DEIS includes a description of the lease proposal, a description of the marine and nearby onshore environment, a detailed analysis of possible adverse impacts on the environment, the technology to be used, the socioeconomic impacts, mitigating measures proposed, alternatives to the proposal, and the records of consultation and coordination with others in preparation of the statement. The DEIS is published in the *Federal Register* with a 60-day comment period, and public hearings on the DEIS are held within the vicinity of the proposed lease sale.

A Final Environmental Impact Statement (FEIS) is then prepared taking into account the comments received during the review period and at the public hearings. The FEIS is filed with the Environmental Protection Agency and made available to the public.

NOTICE OF LEASE SALE

At least 30 days after the submission of the FEIS to the Environmental Protection Agency, a final decision is made by the Secretary of the Interior as to whether or not the proposed sale will be held. A Secretarial Issue Document (SID) is first prepared which analyzes the issues and options pertaining to the sale area, and includes information on alternative terms and procedures to be used in the lease sale. If the decison is to hold a sale, the SID and the final EIS are submitted to the affected States for comment within 60 days. A Proposed Notice of Lease Sale is published in the *Federal Register* identifying the blocks to be leased and the leasing stipulations, terms, and procedures.

After the 60-day comment period, the Final Notice of Lease Sale is published in the *Federal Register*. Taking into consideration public comments and State concerns, the final notice lists the tracts to be included in the sale, the terms under which the sale will be held, and any special stipulations that may be imposed on particular tracts. It also gives at least a 30-day notice of the date, place, and time that bids are to be opened.

LEASE SALE

All leases are sold through a competitive bidding process with firms submitting separate sealed cash bids for each individual tract. All bids are opened and read at a public sale, after which the bids are checked for technical and legal adequacy. In addition, a determination of the adequacy of the high bids is conducted. The acceptance or rejection of each bid occurs within 90 days after the lease sale is held.

LEASE CONTRACT

The oil and gas lease contract grants the right to the lessee to conduct necessary operations to explore, drill and produce oil and gas from a specific tract. The primary term of the lease contract is usually 5 years, although 10-year terms are granted for special conditions, such as ice-prone areas or deepwater sites. During this time, oil and gas in commercial quantities must be found or approved drilling or well reworking operations must be conducted, or the lease is forfeited. Leases may be extended beyond the initial lease terms as long as production is occuring, drilling or well reworking is undertaken, or a special suspension order is obtained.

EXPLORATION

The lessee is obligated to proceed diligently to explore and develop the tract and must submit an exploration plan to the Department of the Interior for approval by the fourth year of a 5-year lease. Details of drilling technology, geophysical equipment, location of exploratory wells, oil spill contingency plans, an air quality analysis, and other relevant geological and geophysical information must be included in the plan. The exploration plan must be accompanied by an environmental report, and certifications of consistency must be obtained from coastal States under the Coastal Zone Management Act. After an environmental assessment, an environmental impact statement if necessary, and a technical review, the Department of the Interior approves, rejects, or modifies the exploration plan.

Before exploratory drilling can be initiated, an Application for Permit to Drill (APD) must be submitted. This includes detailed information on equipment design, well location and depth, and potential geophysical hazards. Additional approvals are required each time a well is deepened, reworked, redrilled, or plugged back. In addition to the Department of the Interior permit to drill, appropriate permits must be received from the

U.S. Coast Guard, U.S. Army Corps of Engineers, Environmental Protection Agency, and other federal agencies to satisfy environmental or safety requirements.

DEVELOPMENT AND PRODUCTION

The planning, environmental assessment, and approval process starts anew when oil and gas is discovered on a tract. A detailed Development and Production Plan and accompanying environmental report must be submitted by the lessee to the Department of the Interior for approval. Certifications of consistency also must be obtained from the coastal zone management programs of the affected States. The plan and environmental report are reviewed by a number of Federal agencies and affected States, and the Department of the Interior prepares its own environmental evaluation and technical review. In addition, a separate platform verification and certification process, involving third-party verfication agents, is initiated for the evaluation and monitoring of platform design, fabrication, and installation.

An APD must be received prior to drilling any development well, and any reworking of development wells also must be approved. All other necessary Federal permits, such as for offshore structures, navigation aids, and pollution discharge, must be obtained prior to approval of the APD by the Department of the Interior. Permits and approvals also must be received for the construction and operation of offshore pipelines and for any significant modification of production equipment and procedures. As production proceeds, the Department of the Interior is responsible for on-site inspection and monitoring of offshore operations. The lessee must submit monthly reports of operations and royalty payments to the government.

RELINQUISHMENT

Leases expire at the end of their initial term unless actual production is occurring or a suspension of production or operation (SOP) is received for development activities or approved drilling or well reworking operations. Leases may also be relinquished by a lessee or cancelled by the Department of the Interior for noncompliance with OCS regulations. At the time of abandonment, the operator must plug the wells in accordance with Interior requirements. All oil and gas zones must be isolated by the installation of cement plugs to ensure a permanent seal. All pipe casings must be cut off below the ocean floor and the well location must be cleared.

Offshore Leasing Revenues

LEASE PAYMENTS

Revenues from offshore leasing consist of bonuses, rents, and royalties in addition to taxes. Bonuses are advance cash payments made by companies for the right to explore and develop particular tracts. Rents are annual fees, now set at $3 per acre, paid on leased acreage. Royalties are pre-set percentages of the value of oil and gas production paid after production begins. The standard royalty rate on offshore production has been 16⅔ percent, although some tracts have been leased with 12½ percent and 33⅓ percent royalties. A few tracts also have been leased with profit share payments and sliding scale royalties rather than fixed royalties.

From the start of the OCS leasing program in 1954 to the end of 1983, bonuses, rents, and royalties from offshore leases have totaled approximately $68 billion (see table A-2). OCS receipts increased from an average of $280 million per year in the 1950s and 1960s to an average of $3 billion per year in the decade of the 1970s. In the early 1980s, OCS receipts averaged more than $8 billion per year. In general, the level of receipts has increased with the quantity of acreage leased, the amount of oil and gas produced, and increases in energy prices.

Bonuses have comprised the largest share of government lease payments (69 percent) other than taxes and account for most of the variation in annual OCS receipts. Bonus receipts increased substantially in 1973-74, as a result of the Nixon administration initiatives to increase offshore leasing, and in 1979-83 as leasing was again accelerated. In 1981, bonus receipts reached a high of $6.6 billion for over 2 million leased acres. Bonus revenues declined from the 1981 level in 1982 and 1983, due to depressed oil prices, the more costly and risky nature of the deepwater and Alaskan tracts being leased, and other factors.

From 1953 to 1983, a total of 6 billion barrels of oil and 62 trillion cubic feet of gas were produced in Federal offshore areas. Although offshore oil production declined every year between 1971 and 1980, it again turned upward in 1981 when 286 million barrels of oil were produced. In 1983, Federal offshore hydrocarbon production represented approximately 11 percent of the oil and 24 percent of the natural gas produced in the United States. The cumulative value of the oil and gas produced offshore between 1953 and 1983 is estimated at $128 billion, of which $20 billion or 16 percent was paid to the Federal Government in royalties. Lease payments by companies (not counting taxes) accounted for

Table A-2.—OCS Acreage, Production, and Revenues (1953-1983)

Year	Sales	Acreage		Production		Revenues ($ billion)			
		Offered	Leased	Oil (mbbl)	Gas (tcf)	Bonuses	Royalties	Rents*	Total
1953				1	0.020	0.000	0.001	0.001	0.002
1954	3	1384238	486870	3	0.056	0.141	0.003	0.004	0.148
1955	1	674095	402567	7	0.081	0.108	0.005	0.003	0.116
1956	0	0	0	11	0.083	0.000	0.008	0.004	0.012
1957	0	0	0	16	0.083	0.000	0.011	0.003	0.014
1958	0	0	0	25	0.127	0.000	0.018	0.002	0.020
1959	2	539813	171300	36	0.207	0.090	0.027	0.002	0.119
1960	2	1632339	707026	50	0.273	0.283	0.037	0.004	0.324
1961	0	0	0	64	0.318	0.000	0.048	0.003	0.051
1962	3	3718115	1929177	90	0.452	0.489	0.067	0.008	0.564
1963	1	669777	312945	105	0.564	0.013	0.078	0.008	0.099
1964	2	1124102	613524	123	0.622	0.096	0.089	0.010	0.195
1965	1	947520	72000	145	0.646	0.034	0.104	0.009	0.147
1966	3	265886	141768	189	1.007	0.209	0.144	0.007	0.360
1967	2	988484	746951	222	1.187	0.510	0.160	0.006	0.676
1968	3	1315984	934164	269	1.524	1.346	0.203	0.008	1.557
1969	3	355758	114282	313	1.954	0.112	0.242	0.009	0.363
1970	2	666845	598540	361	2.419	0.945	0.285	0.009	1.239
1971	1	55872	37222	419	2.777	0.096	0.352	0.008	0.456
1972	2	970711	826195	412	3.039	2.251	0.366	0.008	2.625
1973	2	1514940	1032570	395	3.212	3.082	0.404	0.009	3.495
1974	4	5006881	1762158	361	3.515	5.023	0.562	0.014	5.599
1975	4	7247327	1679877	330	3.459	1.088	0.618	0.018	1.724
1976	4	2827342	1277937	317	3.596	2.243	0.702	0.023	2.968
1977	2	1843116	1100734	304	3.738	1.568	0.921	0.020	2.509
1978	4	3140696	1297274	292	4.385	1.767	1.152	0.022	2.941
1979	6	3413352	1767443	286	4.673	5.079	1.517	0.020	6.616
1980	3	2563452	1134238	277	4.641	4.205	2.139	0.019	6.363
1981	7	7679740	2237005	286	4.880	6.602	3.274	0.021	9.897
1982	5	5815872	1886360	321	4.679	3.987	3.815	0.020	7.822
1983	8	120094037	6593517	341	3.940	5.749	3.376	0.037	9.161
Totals	77	176456294	29863644	6371	62.157	47.116	20.728	0.339	68.182

*Includes minimum royalties, shut-in gas, etc.

SOURCE: Minerals Management Service.

about 53 percent of the total value of oil and gas production in that period.

The greatest share of OCS receipts (83 percent) has been from the Gulf of Mexico (see table A-3 and figure A-2). The Gulf of Mexico, predominantly offshore Louisiana, accounts for over 99 percent of all natural gas production and 96 percent of all oil production in Federal offshore areas. The balance of offshore oil and gas production in Federal waters is from offshore California. As a result, the Gulf of Mexico has accounted for 77 percent of bonus revenues, 97 percent of oil and gas royalties, and 79 percent of all rents received. Leasing

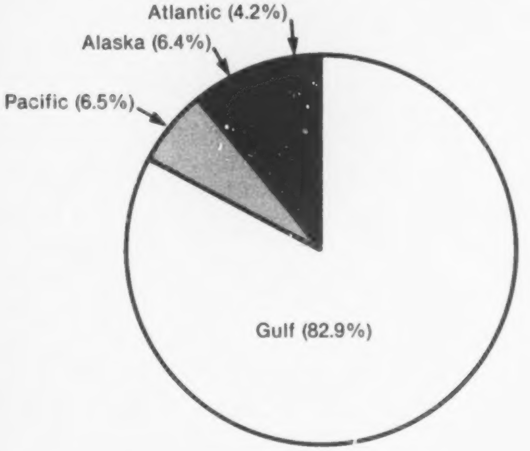
Table A-3.—OCS Regions: Production and Revenues (1953-1983)

Regions	Production		Revenues ($ million)			
	Oil (mbbl)	Gas (bcf)	Bonuses	Royalties	Rents	Total
Gulf	6,096	62,037	36,076	20,196	269	56,541
Pacific	275	120	3,840	532	31	4,403
Alaska	0	0	4,360	0	22	4,382
Atlantic	0	0	2,840	0	17	2,857
Total	6,371	62,157	47,116	20,728	339	68,183

mbbl - million barrels
bcf - billion cubic feet

SOURCE: Minerals Management Service.

Figure A-2.—Federal Revenues From OCS Regions 1953-1983



SOURCE: Office of Technology Assessment.

in the Alaskan and Atlantic offshore regions began in 1976, and while they have contributed some bonus revenues and rents, there is as yet no oil and gas production or royalty revenues from these regions.

FEDERAL TAXES

In addition to lease payments, companies also pay Federal taxes on offshore oil and gas production. In general, the oil and gas producing industry in the United States benefits from special tax provisions designed to encourage domestic energy exploration and production. In recent years, this tax advantage has been reduced by the Crude Oil Windfall Profits Tax. Offshore oil and gas producers may currently expense and deduct certain costs, including intangible drilling costs (up to 80 percent) and dry hole costs, which would normally be recovered through depreciation. Oil and gas producers also benefit from two general provisons of the Federal tax code available to all business: the depreciation deductions under the Accelerated Cost Recovery System and the regular 10 percent investment tax credit.

In 1980, Congress enacted the Crude Oil Windfall Profits Tax, an excise tax per barrel on the difference between the crude oil market price and an established base oil price. The rate varies between 15 and 70 percent depending on the oil tier (e.g., old oil, stripper oil), type of producer, and year of production. The tax on newly discovered oil is to be phased down from the current 22.5 percent to 20 percent in 1988 and to 15 percent in 1989 and thereafter. The Windfall Profits Tax does not apply to oil production from Arctic areas. The Windfall Profits Tax should not apply to oil producers in other offshore frontier areas, as the base price should exceed the market price before fields come on stream in these regions.

REVENUE TRENDS

Owing to the substantial funds received by the Federal Government from offshore leasing, there has been controversy regarding the relationship between offshore leasing and revenue policy. It is widely believed that the pace of leasing has been partly dictated by budget concerns. In the early years of leasing, the Department of the Interior was accused of maintaining a deliberately slow rate of leasing in order to keep the demand for leases and bonus revenues high. In the 1970s, the General Accounting Office (GAO) charged that the government accelerated leasing in order to increase revenues for the general Treasury. Similarly, the accelerated leasing schedule which began in 1982 is believed by some to stem partly from the need to generate revenues and reduce the large Federal budget deficit.

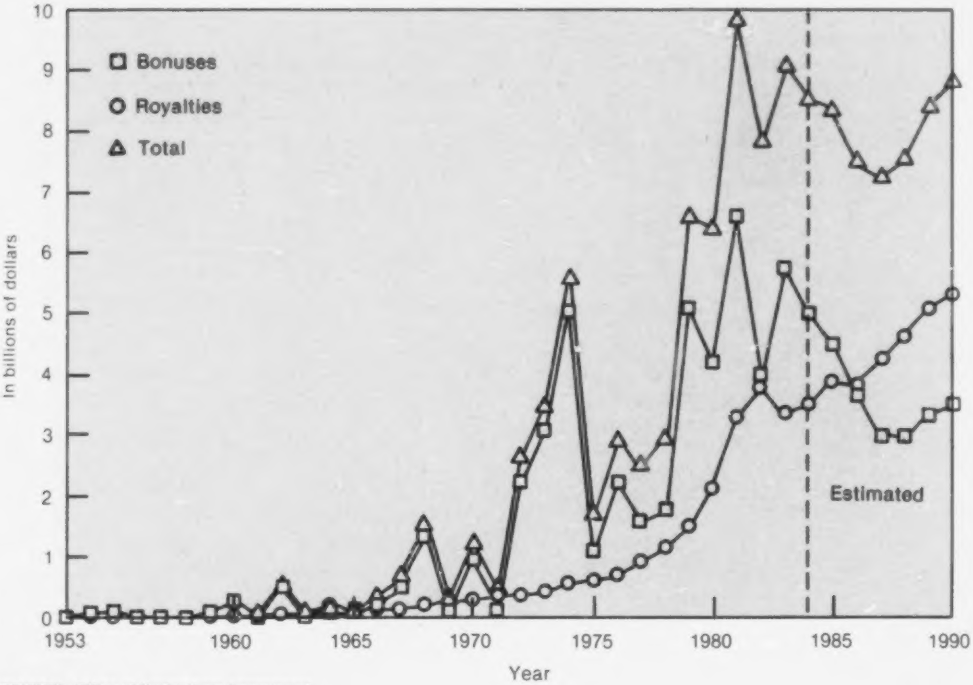
Budget concerns may have also influenced government forecasts of future revenues from OCS leasing. It is difficult to project OCS receipts because of the subjective nature of resource estimates, unpredictability of future prices and development costs, and unforseen changes to lease schedules. The Office of Management and Budget (OMB) has overestimated—by a factor of 2 or more—projected receipts from offshore leasing in the 1980s. The original OMB budget estimates for fiscal year 1984 were for $18 billion in receipts from OCS leasing; this was later revised downward to $12 billion; however, actual fiscal year 1984 OCS leasing revenues were in the area of $8-9 billion. For fiscal year 1985, OMB has again projected $12 billion in OCS revenues, as compared to a Department of the Interior estimate of $6 billion.

The Department of the Interior projects that royalty revenues will surpass bonus revenues for the first time in 1985-86 (see figure A-3). Interior forecasts show that annual bonus revenues will decline to an average $2 to $3 billion per year while royalties level off at $3 to $4 billion per year during 1985-89. At the same time, the costs of post-lease management activities will rise as a result of the increases in leased acreage and the difficulty of operating conditions in frontier areas. The balance between income from offshore leasing and the costs of management programs may change as leasing proceeds in offshore frontier areas.

State Offshore Leasing Policies

The offshore leasing systems used by the coastal States are similar to that used by the Federal Government. Certain aspects of the Federal leasing process were

Figure A-3.—OCS Revenues Forecast
Bonuses and Royalties



SOURCE: Office of Technology Assessment.

adapted from the State experience, such as the one-sixth royalty rate which was that traditionally used for offshore tracts by the State of Louisiana. Louisiana, California, and Texas leased offshore lands under their jurisdiction prior to the enactment of the Submerged Lands Act of 1953, which established offshore State/Federal boundaries, and the 1953 OCS Lands Act, which provided guidelines for the Federal system. Through 1983, the States accounted for 39 percent of the oil and 19 percent of the natural gas produced in the offshore areas of the United States. Currently, State offshore oil and gas production is decreasing. Production in Federal waters now accounts for about 80 percent of total offshore oil production and 88 percent of total offshore gas production.

Although Florida, Alabama, Mississippi, and Washington State have leased offshore tracts, the States of Louisiana, California, Texas, and Alaska have accounted for most of the State offshore activity and are the only States to have offshore hydrocarbon production (see table A-4). Since the start of State leasing in the 1920s, Louisiana has accounted for most of the wells drilled and hydrocarbons produced in State waters. California, which has not issued any leases since 1969, accounts for the highest percentage of oil and condensate produced in State offshore areas. Currently, most State drilling activity is centered off Louisiana and Texas.

The leasing process used by the States is generally similar to the Federal system in its administrative framework, competitive bidding system, and lease terms (see table A-5). As does the Federal Government, the

Table A-4.—State Offshore Leasing Statistics
(cumulative through 1983)

		Production	
State	Wells drilled	Oil* (mbbl)	Gas (bcf)
Louisiana	4,688	1,338	9,654
California	3,598	1,884	716
Texas	1,451	26	2,877
Alaska	379	816	1,126
Other	29	0	0
Total State	10,145	4,064	14,373
Total Federal	22,095	6,371	62,157

*Includes condensate.
mbbl - million barrels.
bcf - billion cubic feet.

SOURCE: Minerals Management Service.

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Table A-5.—Comparison of Federal and State Leasing Policies

	Federal	Louisiana	California	Texas	Alaska
Lead Leasing Agency	Minerals Management Service	State Mineraal Board	State Lands Commission	School Land Board	Department of Natural Resources
Permitting Agencies	EPA, Coast Guard, Army Corps of Engineers	Office of Conservation, Depts. of Natural Res., Env. Quality, and Wildlife & Fish	Coastal Commission (in dispute)	State Railroad Commission	Oil and Gas Cons. Comm. Dept. of Env. Cons. Dept. of Fish and Game Office of the Governor
Frequency of Sales	5-8 year	Monthly	Not since 1969	Twice a year	At least 3 per year
EIS Requred	Yes	No	Yes	No	Yes (for major sales)
Lease Term	5/10 years	5 years	20 years	5 years	10 years
Primary Bidding System	Cash bonus bid/ fixed royalty	Cash bonus and royalty bid	Cash bonus bid/ sliding royalty	Cash bonus bid/ fixed royalty	Cash bonus bid/ fixed royalty
Royalty Rate	12½% or 16⅔%	Estimated 21-26%	Estimated 25%	25%	20%
Rental	$3 per acre annually	1/2 cash bonus	$1 per acre annually	$1 per acre annually	$1 per acre annually
Taxes	Corporate Income Tax Windfall Profits Tax (except in Arctic)	Severance Tax (12.5%)	Corporate Income Tax (9%)	Severance Tax (4.6% oil/ 7.5% gas)	Corporate Income Tax (9.4%) Severance Tax (12.5-15%) Property Tax

SOURCE: Office of Technology Assessment.

States receive revenues from offshore leasing in the form of cash bonuses, royalties, and other types of lease payments, and from various tax levies. The States have typically set higher royalty rates on production than the Federal Government, largely because State offshore areas are nearer to shore and less costly and risky to explore and develop than Federal waters.

Louisiana

Most oil and gas activity in State offshore areas has been off the coast of Louisiana, which has developed a sizeable onshore support, service, and refining base. The first offshore tract was leased in the 1920s, and through 1983, almost 4,700 wells had been drilled in Louisiana waters. Oil and gas production from offshore Louisiana has been declining since the early 1970s. In 1983, Louisiana produced 24 million barrels of oil and 316 million cubic feet of natural gas. In contrast, production in Federal waters offshore Louisiana in 1983 was about 290 million barrels of oil and almost 3 billion cubic feet of gas. Approximately 40 percent of Louisiana's 1 million acres of State offshore lands was under lease as of 1983.

Louisiana conducts monthly lease sales, and State revenues have depended heavily on offshore leasing. The bidding system used in Louisiana is a hybrid with both the cash bonus amount and the royalty rate open to bid. In addition, companies may submit several bids on the same tract. Each bid is considered if it meets the minimum royalty rate of 12½ percent and any specified minimum bonus amount. In the 1980s, it is estimated that the average royalty rate has been 21 to 26 percent. The rental fee is set at one-half of the cash bonus amount for each tract. Lousiana has no corporate income tax, but has a severance tax of 12.5 percent on oil and 7 cents per cubic foot of gas.

California

From the start of leasing in 1929 through 1969, the State of California issued 62 offshore leases. A moratorium was placed on offshore leasing in 1969 as a result of the Santa Barbara Channel blowout. However, drilling on previously leased lands was allowed to continue and some leases were extended. The State is currently planning to resume leasing in the Point Conception/Point Arguello offshore areas, pending the settlement of jurisdictional questions with the California Coastal Commmission. From the start of leasing through 1983, approximately 1.9 billion barrels of oil and 700 billion cubic feet of gas have been produced in the California offshore. This is far more than has been produced in Federal waters offshore the State, representing almost 90 percent of the total oil and gas produced off the coast of California to date.

California traditionally has awarded leases on the basis of a cash bonus bid with a sliding scale royalty rate, set at a minimum of 16⅔ percent. It is estimated that the sliding scale royalty system has resulted in an overall effective royalty rate of 25 percent. Several other types of bidding systems are authorized by California regulations, and the State plans to experiment with net profit share payments in future lease sales. The other lease payment is an annual rental fee of not less than one dollar per acre. Taxes on offshore operators include a 9 percent corporate income tax, which is applicable to the worldwide income of the company. Although the State does not have a severance tax as such, it does levy a small fee on oil and gas production in order to finance offshore administrative and regulatory activities.

Texas

Texas issued its first offshore lease in 1922, drilled the first well in State waters in 1938, and recorded the first production in 1940. Until the 1980s, oil and gas production from State waters remained about equal with that from Federal waters offshore the State. However, oil production in Federal waters has now increased to about 90 percent of total oil produced offshore Texas, while Federal offshore natural gas production increased to 78 percent of the total in 1983. It is estimated that more than two-third's of the State's offshore area has been leased, and that State offshore oil and gas production will continue to decline. In 1983, approximately 2 million barrels of oil and 148 million cubic feet of gas were produced in State waters.

Texas holds lease sales twice a year and leases most offshore tracts by a cash bonus bid/fixed royalty bidding system. However, Texas also has used royalty bidding for 10 to 15 percent of its offshore tracts, primarily those where hydrocarbon prospects were high. In both types of bidding systems, the minimum royalty rate is now 25 percent. Texas also has a graduated rental fee system which increases with the number of years acreage is held, amounting to $1 per acre after the fourth year. The Texas severance tax consists of 4.6 percent on oil production and 7.5 percent on natural gas production, and there is also a small regulatory tax.

Alaska

Alaska issued its first State offshore leases in 1959. Unlike other States with offshore oil and gas production, Alaska has as yet no oil or gas production in Federal waters off the State. However, a probable commercial discovery was announced at Seal Island in the Beaufort Sea in 1984. In 1983, Alaska produced 22 million barrels of oil and 90 million cubic feet of gas from offshore State leases. Offshore gas production has continued to increase, while offshore oil production has declined since the 1970s. There is still substantial activity in State waters where 14 drilling platforms were stationed and 18 wells drilled in 1983, as compared to 3 structures in Federal waters in that year.

Prior to 1978, Alaska used the Federal bidding system of cash bonus bid and 16⅔ or 12½ percent royalty in leasing State offshore tracts. Amendments to Alaska's oil and gas leasing laws in 1978 broadened the State's bidding methods. Since 1978, Alaska has leased a greater number of tracts with sliding scale royalties as well as with profit share and royalty rate bidding. In addition, the minimum royalty rate was increased to 20 percent. This was due to concern about declining oil production and the desire to increase revenues from potentially large oil and gas discoveries, particularly downstream revenues. Alaska is one of the few States which collects more revenues from oil and gas production in the form of taxes than in the form of lease payments. These taxes include a corporate income tax, a property tax, and a severance tax, which increases from 12.5 percent to 15 percent of the value of oil and gas production after 5 years.

Foreign Offshore Leasing Policies

Comparison of U.S. and Foreign Systems

The offshore leasing systems used in other countries differ from that used in the United States. Canada, the United Kingdom, and Norway, as well as the United States, are currently leasing offshore tracts in high-risk, high-cost regions of the Arctic and the North Sea. These areas are characterized by harsh operating environments that require complex planning, long lead-times to first production, high capital outlays, and the use of innovative technologies. In the design of its leasing system for offshore frontier areas, the United States differs from these countries in several aspects (see table A-6).

ALLOCATION OF LEASE RIGHTS

The United States is one of the few countries to grant leases solely on the basis of financial competition. Most other countries rely on governmental discretion and industry-government negotiation to award lease rights. Foreign lease allocation is by subjective comparison of the qualifications and terms being offered by applicants. After negotiation with the firm, foreign governments may include stipulations in the leases to ensure rapid exploration and development of specified areas, provide for government participation in oil and gas production, protect the environment, provide for local employment, or further other national goals. While discretionary allocation provides greater scope for government influ-

Table A-6.—Comparison of United States and Foreign Offshore Leasing Policies

	United States	Canada	United Kingdom	Norway
Leasing Provisions				
Allocation	Competitive	Discretionary	Discretionary	Discretionary
Lease terms	5/10 years or as long as producing	Exploration: 5 years Production: 10 years, renewable for 10 years	Exploration: 3 years Production: 6 years, renewable for 40 years	Exploration: 3 years Production: 6 years, renewable for 30 years
Work program	None	Yes	Yes	Yes
Relinquishment	None	50 percent of acreage	Up to 2/3 of acreage	50 percent of acreage
Average tract size	25 sq. km	2000 sq. km	250 sq. km	550 sq. km
Financial Provisions				
Government participation	None	25 percent (optional)	None	>50 percent (optional)
Lease payments	Cash bonus, 12½% or 16⅔% royalty	10% royalty, plus incremental royalty	12½% royalty (none for frontier areas)	Sliding scale royalties
Incentive payments	None	Up to 80% for Canadian firms, 25% for foreign firms (exploration only)	None	None
Taxes	Corporate Tax: 46% Windfall Profits Tax (except in Arctic)	Corporate Tax: 46% Petroleum Revenue Tax: 12%	Corporate Tax: 52% Petroleum Revenue Tax: 75%	Corporate Tax: 50.8% Special Petroleum Tax: 35%

SOURCE: Office of Technology Assessment.

ence than competitive bidding, it is also more expensive to administer.

LEASE STAGES

The United States is unique in jointly granting leases for offshore exploration and development. Other countries make a greater distinction between exploration and development lease rights. In these countries, exploration leases are granted for large areas for terms of 3 to 5 years, specify the work to be completed, and require that all data be shared with the government. If a discovery is made, the terms of a production lease are then negotiated. The advantage of the two-stage system is that it provides for rapid exploration of large offshore areas and gives the government greater flexibility in establishing production lease terms.

WORK PROGRAMS

In the United States, lease rights are obtained through the payment of upfront bonuses, which provide an incentive for firms to engage in efficient exploration and development so as to recover the initial investment. The U.S. government only requires the submission of exploration and development plans and diligent exploration. The discretionary allocation method used by other countries usually entails a mandatory work program negotiated in conjunction with the lease rights. This may consist of detailed exploration and development plans, drilling of a certain number of wells, and/or a minimum expenditure. Firms which fail to carry out the terms of the work program can lose lease rights or any collateral paid to the government. Work commitments ensure rapid exploration and development, but also can be expensive to administer.

RELINQUISHMENT

Other countries usually have relinquishment requirements for nonproductive acreage in conjunction with much larger tract sizes. Canada, the United Kingdom, and Norway have stipulations in their exploration and/or production leases that firms relinquish, at specified times, a certain percentage of their tracts. This requirement forces companies to explore rapidly to determine the most promising acreage for further exploration and development. In addition, the initial tracts leased for exploration are 10 to 80 times larger than tracts in the United States, which are limited to 25 square kilometers. The United States has an indirect incentive for relinquishment of nonproductive acreage in its tax system, which allows companies to write off expenses related to dry holes or nonproductive tracts.

FINANCIAL PROVISIONS

The United States relies primarily on lease payments for government income from offshore oil and gas development. In Canada, the United Kingdom, and Norway, the primary revenue source is government participation and/or taxation. The United States is also one of the few countries to require an upfront cash bonus payment for lease rights, rather than stretching out all lease payments over the life of the field. The United States uses a fixed royalty on production, rather than a sliding scale or incremental royalty linked to field productivity. The United States, like other countries, gives some incentive to exploration through its tax system, but does not offer direct exploration subsidies as does Canada.

Foreign Leasing Systems

CANADA

Canada began offshore leasing in the late 1950s and initiated leasing in the frontier Arctic areas (with as yet no production) in the 1960s. After the introduction of the National Energy Program in 1980, these leases were renegotiatied into exploration agreements and over a hundred new agreements were entered into for exploration in frontier areas. In recent years, Canada's offshore leasing program has been focused on rapid exploration and development of resources, achievement of national energy self-sufficiency, and increased government participation in the oil and gas industry. Since the 1984 national elections, the offshore leasing and financial terms have been under government review.

Canada has a two-stage leasing system, where exploration and production licenses are granted separately and different procedures govern each. Exploration agreements are made on a discretionary basis, usually with provisions for work commitments. They are granted for large areas, averaging 2000 square kilometers, and include measures for relinquishment of 50 percent of the acreage at the end of the initial 5-year term. The remaining lease area may be retained by renegotiating the exploration agreement. Production licenses may be obtained by lessees at any time and are renewable in 10-year increments.

Since 1980, Canada has increased government participation in oil and gas development and enacted an exploration subsidy program which favors Canadian-owned firms. The Canadian national oil company, Petro-Canada, has the right to a 25 percent working interest in any commercial discovery on offshore tracts. The Petroleum Incentives Program initiated in 1982 reimburses Canadian-owned companies for up to 80 percent and foreign companies for up to 25 percent of eligible exploration costs. This program replaced the favorable "superdepletion" provisions allowed against the Corporate Income Tax, which still allows the immediate deduction of both tangible and intangible drilling costs. In addition, Canada has a Petroleum and Gas Revenue Tax levied since 1981 at an effective rate of 12 percent on gross income. Together with a fixed 10 percent royalty, this tax makes the Canadian revenue system on offshore fields somewhat regressive. Canada also has a progressive incremental royalty on net income from offshore production.

UNITED KINGDOM

The United Kingdom has leased offshore tracts since the mid-1960s, but leasing in the northern North Sea tracts did not begin until the early 1970s. The United Kingdom has relied on frequent adjustments to a complicated tax system to influence the level of offshore activity and the flow of government revenues. In 1983, the financial terms for offshore leasing were liberalized to encourage exploration in frontier areas and the development of marginal fields.

The United Kingdom has held eight oil and gas "leasing rounds," each characterized by different leasing and financial provisions. The government has generally used a discretionary system for offshore leasing, but has experimented with competitive bidding and offered 15 North Sea blocks for cash bonus bids in the eighth leasing round in 1982-83. Exploration licenses are granted for periods of 3 years and specify a schedule of geological and geophysical surveys and well drilling. All data are to be relinquished to the government. Production licenses also involve negotiated work programs and are granted for initial terms of 6 years. Tracts are ten times larger than those in the United States, averaging 250 square kilometers in size, but up to two-thirds of the tract must be relinquished at the end of the initial term.

The United Kingdom traditionally has relied on government participation and taxation for the major share of revenues from offshore leasing. However, companies no longer have to take the British National Oil Corporation as a partner in offshore development, although some licensing preference is still given to groups which include government participation. In 1983, the government changed the lease terms and tax provisions to spur offshore exploration and development. Royalties were eliminated for northern North Sea fields, although a 12½ percent production royalty is still charged for other areas. Firms now may recover all exploration and development costs prior to paying the Petroleum Revenue Tax, which is field specific. They also receive special allowances for small fields. In addition, the Corporation Tax, which is "ringfenced" to offshore fields, is being decreased gradually from a rate of 52 percent to 35 percent in 1986-87.

NORWAY

Norway began offshore leasing after the passage of the Continental Shelf Act of 1963, and oil from North Sea areas is now being produced under some of the most difficult operating conditions in the world. Leasing policy has changed emphasis from encouraging rapid exploration and development to increasing government returns from oil and gas development. Norway gains substantial income from offshore hydrocarbon production from an excess profits tax and a requirement that at least a 50 percent equity interest in every tract be given to the Norwegian State Oil Company, Statoil.

Norway uses a discretionary, two-stage system for allocating lease rights, with initial exploration licenses granted for large offshore areas. The licenses are for periods up to 3 years and contain provisions for data-sharing with the government. Production licenses with mandatory work programs are valid for initial terms of 6 years for initial tracts averaging 550 square kilometers. Production licenses can be renewed for an additional 30 years for 50 percent of the original area.

The Norwegian government obtains oil and gas revenues from state participation, taxation, and moderate royalties on production. Since 1972, Statoil has had at least 50 percent equity in all production licenses and has been appointed operator for more than one-third of these licenses. Norway has a Corporate Tax and also a Special Petroleum Tax on net income. The Special Petroleum Tax is calculated on the basis of total offshore operations, and unlike the British Petroleum Revenue Tax, does not contain any exemptions for small fields. As a result, the Norwegian marginal tax rate is extremely high for all fields and has caused Norwegian authorities to undertake a review of the current tax system. In addition, Norway has a system of sliding scale royalties on petroleum production and a flat 12½ percent royalty on natural gas.

Appendix B

Glossary

Bidding System: Combination of bid variable and other lease payment(s) used for allocation of lease rights, e.g., cash bonus bid and fixed royalty.

Blowout Preventer: The equipment installed at the wellhead to prevent the escape of pressure.

Break-up: The period in the Arctic during which ice in water bodies thaws and breaks up (late May to mid-June for river ice, early July to mid-August for ocean ice.)

Cash Bonus: Money paid by a lessee for the execution of an oil and gas lease.

Casing: Steel pipe placed in an oil or gas well as drilling progresses to prevent the wall of the hole from caving in during drilling and to provide a means of extracting petroleum if the well is productive.

Commercial Accumulation: An occurrence of oil and gas that meets the minimum requirements for size and accessibility to be of commercial interest to a company. The term commercial is frequently synonymous with economic.

Deferral: Temporary exclusion of specific offshore areas from leasing.

Development Well: A well drilled in proven territory in a field to complete a production pattern.

Directional Drilling: Drilling at an angle from the vertical. Directional drilling makes it possible to reach subsurface areas laterally remote, from the point where the bit enters the earth.

Discovered Resources: That portion of the oil and gas in the earth whose presence has been physically confirmed through actual exploration drilling.

Discovery Well: The first oil or gas well drilled in a new field; the well that reveals the presence of a petroleum-bearing reservoir. Subsequent wells are development wells.

Drill Ship: A ship constructed to permit a well to be drilled from it at an offshore location. While not as stable as other floating structures, drill ships are capable of drilling exploratory wells in relatively deep waters.

Dynamic Positioning: A method by which a floating offshore drilling rig is maintained in position over an offshore well location. Several motors called thrusters are located on the hulls and are activated by a sensing system, which maintains the rig on location.

Economic Rent: Profits from oil and gas development in excess of a firm's normal return to capital.

Economies of Scale: Reduction in costs stemming from a larger scale of operations or higher units of production.

Environmental Impact Statement (EIS): A document required by the National Environmental Policy Act (NEPA) of 1969 or similar State law in relation to any action significantly affecting the environment.

Fair Market Value: Price a property brings in a competitive market where either party to the transaction has the freedom to reject the offer.

Freeze-up: The period in the Arctic during which lakes, rivers, and other water bodies freeze.

Indicated Reserves: Known oil and gas that is currently producible but cannot be estimated accurately enough to qualify as proved.

Inferred Reserves: Reserves that are producible but the assumption of their presence is based on limited physical evidence and considerable geologic extrapolation. This places them on the borderline of being undiscovered. The accuracy of the estimate is very poor.

In Place: All of the oil and gas in the reservoir, combining both the recoverable and nonrecoverable portions.

Ice Leads: Large openings in sea ice.

Jack-up Drilling Rig: An offshore drilling structure with tubular or derrick legs that support the deck and hull. When positioned over the drilling site, the bottoms of the legs rest on the surface. A jack-up rig is towed or propelled to a location with its legs up. Once the legs are firmly positioned on the bottom, the deck and hull height are adjusted and levelled.

Landfast Ice Zone: The area extending from the shore and consisting of two sub-zones: bottomfast ice, where sea ice is frozen to the bottom, and floating fast ice, seaward of the bottomfast ice and extending outward from shore.

Lease: A contract authorizing exploration for and development and production of oil and gas in a specific offshore tract.

Lease Sale: Competitive auction for offshore leases by sealed bid.

Leasing System: Combination of bidding systems and other leasing conditions (terms, tract size, etc.) used in offshore leasing.

Lease Term: Period of time granted for offshore lease rights.

Lease Tract: Geographical and legal extent of a single offshore lease area.

Lessee: Firm or group of firms holding lease rights.

Marginal Field: Recoverable reserves of oil and gas which are barely profitable to produce.

Minimum Economic Field Size: Recoverable reserves of oil and gas which are needed to assure profitable production.

Moratoria: Temporary exclusion of specific offshore areas from leasing.

Net Present Value: Total combined value in current dollars of future costs and revenues associated with a project.

Oil Basin: A large basin-like geologic structure in which oil and gas fields will be found.

Oil Field: A geologic unit in which one or more individual, structurally and geologically related reservoirs are found.

Oil Region: A large oil-bearing area in which oil basins and fields are found in close proximity.

Pack Ice Zone: The area in which sea ice consists predominantly of multi-year floes; the area in which ice does not melt annually.

Permafrost: Permanently frozen ground.

Profit Share: Lease payment based on percentage of net income or profits from oil and gas production.

Proved Reserves: An estimate of oil and gas reserves contained primarily in the drilled portion of fields. The data to be employed and the method of estimation are specified so that the average error will normally be less than 20 percent. May also be called measured reserves.

Rent: Money paid by a lessee for the right to occupy an offshore tract.

Reservation: Offshore area permanently withdrawn from leasing.

Reservoir: A natural underground container of hydrocarbons.

Reserves: Oil and gas that has been discovered and is producible at the prices and technology that existed when the estimate was made.

Resource Base: The total amount of oil and gas that physically exists in a specified volume of the earth's crust.

Resources: The total amount of oil and gas including reserves that is expected to be produced in the future.

Royalty: Lease payment based on percentage of gross income or total value of oil and gas produced.

Semi-submersible Drilling Rig: A floating offshore drilling structure that has hulls submerged in the water but not resting on the seafloor. Semi-submersible rigs are either self-propelled or towed to a drilling site and either anchored or dynamically positioned over the site or both. Semi-submersibles are more stable than drill ships and are used extensively to drill wildcat wells in rough waters such as the North Sea.

Shorefast Ice Zone: Two subzones of ice; bottomfast ice, where sea ice is frozen to the bottom, and floating fast ice, seaward of bottomfast ice.

Sliding Scale Royalty: Lease payment based on a royalty rate which increases with the amount of oil and gas production.

Subeconomic Resources: Oil and gas in the ground that are not producible under present prices and technology but may become producible at some future date under higher prices or improved technology.

Submersible Drilling Rig: An offshore drilling structure with several compartments that are flooded to cause the structure to submerge and rest on the seafloor. Most submersible rigs are used only in shallow waters.

Tundra: A rolling, treeless, often marshy plain.

Undiscovered Resources: Resources which are estimated totally by geologic speculation with no physical evidence through drilling available.

Windfall Profits Tax: Tax on profits from oil and gas development brought about by increased prices which are not accompanied by increased costs.

Withdrawal: Permanent exclusion of specific offshore areas from leasing.

Work Commitment: Extent of exploration on an offshore lease to be carried out by the lessee.

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